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Northern Great Plains Resources Program, Denver, Colo

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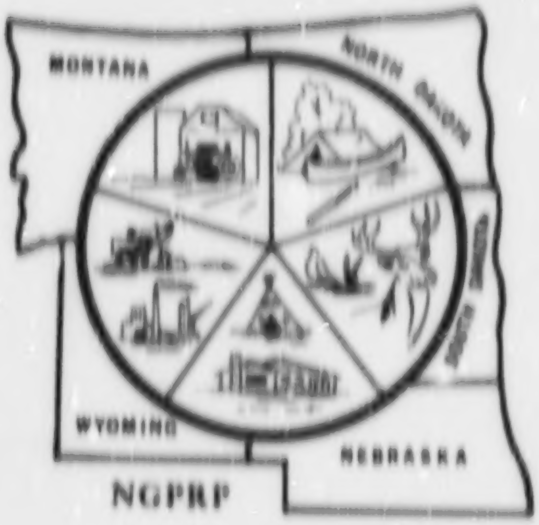
A Review of Major Issues and Consequences at Different Rates of Development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and Private Organizations

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Northern Great Plains Resources Program
ROOM 8205, BUILDING 67
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DENVER, COLORADO 80225

June 23, 1975

Honorable Royston C. Hughes
Assistant Secretary, Department of the Interior
Chairman, Program Review Board of the Northern
  Great Plains Resources Program
Washington, D.C. 20240

Dear Mr. Hughes:

The enclosed report, "Effects of Coal Development in the Northern Great Plains" dated May 1975, has been prepared in accordance with the direction of the Program Review Board and is submitted for your approval.

The report is a summary of information received from seven work groups comprised of representatives from Federal and state agencies, private industry, and other public and private entities.

Also included is the "Declaration of Indian Rights to the Natural Resources in the Northern Great Plains" prepared by the member tribes in the Native American Natural Resources Development Federation of the Northern Great Plains, "Rehabilitation Potentials and Limitations of Surface-Mined Land in the Northern Great Plains" by Paul E. Packer, USDA Forest Service, and "Possible Development of Water from Madison Group and Associated Rock in Powder River Basin, Montana-Wyoming" by Frank E. Swenson, U.S. Geological Survey.

The dedicated effort of all participants is appreciated.

Respectfully submitted,

John G. VanDerwalker

John G. VanDerwalker

Approved: Royston C. Hughes
Royston C. Hughes

Date: June 23, 1975

EFFECTS OF COAL DEVELOPMENT IN THE NORTHERN GREAT PLAINS

A Review of Major Issues and Consequences at Different Rates of Development

Participating States and Federal Agencies

Montana
Nebraska
North Dakota
South Dakota
Wyoming
Environmental Protection Agency
Department of Agriculture
Department of Interior

Coordinated by

The Northern Great Plains Resources Program Staff Denver, Colorado, and Washington, D.C.

Preface

One way to supplement the diminished natural gas and oil reserves of the Nation is by expanded development of its large coal deposits. This report describes cooperative studies of several major impacts of increased production of coal from deposits in the Northern Great Plains region at different theoretical rates of development during the next 25-year period.

The purpose of the report is to provide information that will be useful in developing a perspective of the issues and consequences of expanded development of coal in the region. The reported studies are expected to be helpful in the decisionmaking processes of individuals; Federal, State, and local governments; industry; and other public and private groups.

The report has been coordinated and prepared by the Management Team of the NGPRP (Northern Great Plains Resources Program). The NGPRP was organized in 1971 as a joint effort by three Federal agencies: the Department of the Interior, the Department of Agriculture, and the Environmental Protection Agency; the State governments of Montana, Nebraska, North Dakota, South Dakota, and Wyoming; and other entities to provide a focal point for the collection, coordination, and communication of knowledge of the natural resources of the Northern Great Plains and the relationship of human activities to the resources.

The reported studies and investigations were made by seven Work Groups, whose specific subject areas were: Regional Geology; Mineral Resources; Water; Atmospheric Aspects; Surface Resources; Social, Economic, and Cultural Aspects; and National Energy Considerations. The individual reports of the Work Groups are in the repositories and centers listed in Appendix E to this report. Although the Work Group Studies are basic to this report, the summarization of the vast amount of information assembled by the Work Groups is the accepted responsibility of the Management Team. Additional data have been received from the Work Groups since the completion of their reports; the analyses of these data are included in this report. The contributions of the NGPRP technical advisors and numerous others are also reflected in the report.

Analyses of the effects of different rates of coal development are based on three predesignated "CDP's" (Coal Development Profiles). CDP-I is for a "low" level of development; CDP-II, "intermediate"; and CDP-III, "high." These alternatives are for study and comparison only; they do not represent specific plans or proposals. Each profile (CDP-I, CDP-II, and CDP-III) is analyzed in three time frames—1980, 1985, and 2000.

Considerable attention has been given to the recognition of knowledge gaps and the identification of areas where further research or study is needed.

The report should not be construed as reflecting the positions or conclusions of participating agencies nor the State or Federal governments to which they belong. Rather the report is directed toward a better understanding of the issues associated with coal development in the Northern Great Plains so that critical assessments and decisions are facilitated.

CONTENTS

Letter of Transmittal
Preface

Section Page

PART I–INTRODUCTION

1-1 National Energy Consumption 1
1-2 NGP Coal Resources 1
1-3 Concerns of the People 2
1-4 The Northern Great Plains Resource Program 3
1-5 Scope of Report 4

PART II–THE COAL RESOURCE OF THE NORTHERN GREAT PLAINS

2-1 Issues 5
2-2 The Coal Resource 5
2-3 Ownership Patterns of the Surface and Mineral Estate 7
2-4 Federal and Other Coal Leases 10
2-5 Mining Methods 11
  a. Longwall Mining 11
  b. Underground Versus Surface Mining 12

PART III–ENERGY DEVELOPMENT IN THE NGP

3-1 Introduction 17
3-2 National Energy Consumption Forecast 18
3-3 The Need for Additional Energy Supplies 19
3-4 The Potential for Energy Conservation 22
3-5 Recent Studies 24
3-6 Markets for NGP Coal 25
  a. Export Market for NGP Coal 27
  b. Market for NGP Synthetic Natural Gas 33
  c. Generation and Export of Electric Power 34
  d. Market Conclusions 38

3-7 Federal and State Actions That Might Affect Development 38
  a. State Policies 38
  b. Mineral Leasing Policy 38
  c. Import Policies 38
  d. Environmental Quality Standards 38
  e. Research and Development Support 39

CONTENTS—Continued

Section Page

3-8 Method Used to Assess Range of Potential Changes . . . 39

a. Rationale for Use . . . 39
b. Siting of Mines and Plants . . . 42
c. Importance of NGP Coal by CDP . . . 43
d. Current Outlook in Relation to the CDP's . . . 43

PART IV—LAND, WATER, AND AIR RESOURCES OF THE NORTHERN GREAT PLAINS

A. Introduction

4-1 General . . . 45

a. Resources of National Importance . . . 45
b. Resources of Regional Importance . . . 46

B. Land Resources

4-2 General . . . 47

a. Ecosystems of the NGP . . . 48

(1) Grasslands . . . 48
(2) Flood plains . . . 49
(3) Badlands . . . 51
(4) Brushlands . . . 51
(5) Ponderosa pine . . . 52
(6) Mountains . . . 52

b. Rehabilitation Potential of the NGP Surface Minable Land . . . 52
c. Impacts of Coal Development on Surface Resources . . . 55

(1) Analytical method . . . 55
(2) Summary of surface area to be disturbed . . . 58
(3) Assessment of impacts . . . 59

(a) Soils . . . 59
(b) Vegetation . . . 60
(c) Agriculture . . . 60
(d) Wildlife . . . 60
(e) Wild land . . . 63
(f) Scenery . . . 64

CONTENTS—Continued

Section Page

C. Water Resources

4-3 General 64
4-4 Historic Background 64
4-5 Surface Waterflow Conditions 65

  a. Yellowstone River Basin, Montana, and Wyoming 65
  b. Western Dakota Tributaries of the Upper Missouri River 65
  c. Main Stem Missouri River 65

4-6 Current Trends and Uses 67
4-7 Water Demand 70

  a. Water for Coal Conversion 70
  b. Water for Municipal and Domestic Use 73
  c. Water for Revegetation of Mined Lands 73
  d. Water for Slurry Pipeline Export 74
  e. Total Potential Water Demand 74

4-8 Water Availability 75

  a. Yellowstone River Basin 77
  b. Western Dakota Tributaries 80
  c. Main Stem Missouri River 81
  d. Deep Ground Water 81

4-9 Water Costs 82

  a. Surface Water 82
  b. Ground Water 83
  c. Effect of Water Cost on Development 83

4-10 Issues Which May Influence Water Cost, Availability, or Use 85

  a. Agricultural and Industrial Competition for Water 85
  b. Indian Water Rights 87
  c. Article X of the Yellowstone River Compact 87

4-11 Impacts of Water Development 88

  a. Water Quality 88

    (1) Present conditions 88
    (2) Potential changes in water quality 91

CONTENTS—Continued

Section — Page

        (a) Surface mining impacts . . . 91
        (b) Coal gasification and powerplant impacts . . . 92
        (c) Sewage treatment impacts . . . 95

    b. Shallow Ground-Water Impacts . . . 96

        (1) Impacts on ground-water availability . . . 96
        (2) Impacts on ground-water quality . . . 97

    c. Impact of Water Development on Land Resources . . . 99

D. Air Resources

4-12 Ambient Air Quality . . . 99
4-13 Impact of Coal Conversion on Air Quality . . . 102

    a. Primary Impacts . . . 102
    b. Secondary Impacts . . . 114
    c. Potential Constraints to Coal Conversion . . . 114

4-14 Research and Analysis Needs . . . 117

PART V—THE ECONOMIC, SOCIAL, AND CULTURAL IMPACTS OF COAL DEVELOPMENT IN THE NGP

5-1 Introduction . . . 117
5-2 The Principal Impact Area and Changes Expected as a Result of Coal Development . . . 118

    a. Employment . . . 119
    b. Population . . . 120

        (1) Migration . . . 122
        (2) Spatial distribution . . . 122

5-3 The Principal Impact Communities and Changes Expected From Coal Development . . . 123

    a. Labor Supply . . . 125
    b. Population . . . 126
    c. Institutional and Community Services . . . 127
    d. Housing . . . 129

CONTENTS—Continued

Section Page

(1) Operational phase 132
(2) Construction phase 132

e. Revenue 133

(1) Tax revenues 134
(2) Coal royalty revenues 134
(3) Summary 134

5-4 Impact on Indians as a Result of Coal Development 135

a. The Six Most Affected Reservations 136
b. Population 136
c. Age 136
d. Labor Force and Employment 137
e. The Indian Family and Income 137
f. Educational Levels 137
g. Anticipated Reservation Coal Development 138

5-5 Agriculture—The Present Setting 139
5-6 Agricultural Impact Assessment 141

a. Labor 141
b. Water 142
c. Land 142

5-7 Societal and Cultural Impacts of Coal Development 146

APPENDICES

A.—Organization for Northern Great Plains Resources Program 151
B.—Repositories 153
C.—Principal Agency Participants in Northern Great Plains Resources Program 161
D.—Supporting Documents 163
E.—Maps 165

LIST OF TABLES

Table

II-1 Coal resource of the 63-county study area 5
II-2 Estimated coal reserve base of the NGP 6
II-3 Acres underlaid by surface mineable coal in the NGP 6
II-4 Surface and mineral ownership of study area by owner and State 9

LIST OF TABLES—Continued

Table		Page
II-5	Federal mineral and surface ownership	10
II-6	Federal coal leases in the NGP States	11
II-7	Federal, State, private, and Indian acres under lease for coal in NGP States	12
II-8	Comparison of surface and underground mining	13
III-1	Annual production of coal in NGP States	17
III-2	Reported coal selling price at mine—1973	17
III-3	U.S. energy sources, 1973	21
III-4	Petroleum sources	22
III-5	Coal production—NGP and others	26
III-6	Future coal production—NGP	26
III-7	Price of NGP coal in midwest markets compared to prices of midwest coal	28
III-8	Btu values and allowable sulfur content	30
III-9	Transportation costs of energy	33
III-10	Competitive supplementary gaseous fuels	35
III-11	NGP five-state region—Projected additions of electric generating capacity, 1972-1990	36
III-12	Coal development profile data	40
III-13	NGP coal production	43
III-14	Coal production from each NGP State for each CDP	44
IV-1	Onsite rehabilitation costs	54
IV-2	Total acres of lands impacted in the NGP	56
IV-3	Cumulative acres of projected habitat losses to coal development in the study area	57
IV-4	Campbell County land area disturbed by mining and coal conversion facilities	58
IV-5	Bighorn County land area disturbed by mining and coal conversion facilities	59
IV-6	Rosebud County land area disturbed by mining and coal conversion facilities	59
IV-7	Oliver and Mercer Counties land area disturbed by mining and coal conversion facilities	60
IV-8	Days for which flows of less than 0.1 ft^3/second were recorded and average annual flow in the Yellowstone and Western Dakota tributaries	69
IV-9	Federal industrial water option contracts and applications as of October 1974	71
IV-10	Comparison of potential water requirements for each CDP during years 1980, 1985, and 2000	73
IV-11	Estimated additional municipal water needs for the region by 2000	74
IV-12	Water requirement for revegetation, year 2000	74
IV-13	Water requirements for slurry pipeline export of coal, year 2000	75
IV-14	MBIAC projected surface water demands for year 2000	76
IV-15	Coal development related water demands for 2000—CDP III	76
IV-16	Water availability in the Yellowstone Basin	78

LIST OF TABLES—Continued

Table | Page

IV-17 Water available from Western Dakota tributaries 81
IV-18 Main stem Missouri River storage capacity at selected sites 81
IV-19 Water supply systems costs by CDP 83
IV-20 Summary of per acre-foot water costs by CDP 84
IV-21 Estimates of cost of wells, pumps, and related facilities to supply water for selected hypothetical power and gasification plants 86
IV-22 Comparison of CDP II water costs 87
IV-23 Cost of providing water to selected plant sites by alternative conveyance systems 88
IV-24 Water quality summary 89
IV-25 Projected annual average total dissolved solids concentrations resulting from assumed discharge from coal gasification and power generation plants 94
IV-26 Northern Great Plains mean mixing heights 101
IV-27 Estimated emissions—1972 data in thousands of tons per year 102
IV-28 NAAQS (National Ambient Air Quality Standards) 107
IV-29 NSPS standards 108
IV-30 Significant air deterioration 108
IV-31 Estimated annual air quality concentrations 110
IV-32 Estimated short-term air quality concentrations 110
IV-33 Estimated emissions from projected coal conversion facilities in tons per year 113
V-1 The coal energy development facilities implemented by CDP by type and by year for Montana, North Dakota, and Wyoming 119
V-2 Total employment—Principal impact area 1970-2000 120
V-3 Estimated employment related to coal development in principal impact areas 121
V-4 Coal-related direct operating employment by CDP for Montana, Wyoming, and North Dakota 123
V-5 Agricultural employment projections for Montana, North Dakota, and Wyoming 123
V-6 Total population projections, CDP I, II, III—1980, 1985, 2000 124
V-7 Type of taxes and levels of Government to which the revenues accrue 126
V-8 Population projections for selected communities CDP I, II, III—1980, 1985, 2000 128
V-9 Number of school-age children and associated capital costs required to provide necessary facilities resulting from the operational phase of coal development—Selected communities—CDP II, III—1980, 1985, 2000 130
V-10 Perspective of future needs for new roads and streets 131
V-11 Coal-induced housing needs for selected communities—Operational phase development 133
V-12 Indian land and residents, by reservation, 1973 136
V-13 Indian population change, 1963-73 136
V-14 Unemployment Rates: North Dakota, South Dakota, and Montana, compared to Indian reservations within their boundaries, 1970 137
V-15 Family size and income: Indians compared to total population 138

LIST OF TABLES—Continued

Table Page

V-16 Land use summary—NGP study area by state—In millions of acres 140
V-17 Cumulative agricultural acres displaced as a result of coal development in the Northern Great Plains Study Area CDP I, II, and III 143
V-18 Cropland and associated production displaced annually between 1980 and 2000—CDP II and III 144
V-19 Total acres of rangeland displaced in study area and value foregone 1980-2000, CDP's I, II, and III 145
V-20 Total animal units (AU) of grazing in five-county concentrated area and displacement—Year 2000 146
V-21 Total acres of rangeland displaced in five-county concentrated impact area and value foregone—1980-2000, CDP's I, II, and III 147

LIST OF FIGURES

Figure

III-1 U.S. energy consumption by major source 18
III-2 U.S. potential energy production/consumption 19
III-3 U.S. nuclear-powered electricity production/consumption 20
III-4 U.S. coal production and consumption 20
III-5 U.S. petroleum production and consumption 20
III-6 U.S. natural gas production and consumption 21
III-7 Alternative energy demand projections 24
III-8 Energy conservation 25
III-9 Forecast of coal production in the Northern Great Plains 26
III-10 Allowable sulfur content for coals having different Btu values and assuming different percents of conversion 30
III-11 Estimated average minimum delivered cost of coals in cents per million Btu—1980 by unit train 32
III-12 Location in 63-county study area of new coal-fired electric powerplants projected for operation, 1972-1985 37
III-13 Various forms of coal use for each CDP 42
IV-1 Relative quality of antelope habitat in the NGP study region 47
IV-2 Relative quality of turkey habitat in the NGP study region 48
IV-3 Historic Yellowstone River Basin flows 66
IV-4 Releases from Yellowtail Dam 67
IV-5 Historic western North Dakota riverflows 68
IV-6 Releases from Garrison Dam 69
IV-7 Increase in annual average depletion from 1949 to 1970 70
IV-8 Water diverted from Lake Sakakawea for coal conversion facilities in North Dakota—Year 2000 82
IV-9 Atmospheric aspects study area 100
IV-10 Surface wind roses annual 101
IV-11 Carbon monoxide—Ambient air quality data and standards 103
IV-12 Particulate matter—Ambient air quality data and standards 103
IV-13 A, B, and C nitrogen oxides—Ambient air quality data and standards 104

LIST OF FIGURES—Continued

Figure Page

IV-14 Photochemical oxidants and hydrocarbons ambient air quality data and standards . . . 105
IV-15 Sulfur oxides—Ambient air quality data and standards . . . 106
IV-16 Maximum ambient particulate concentrations . . . 111
IV-17 Maximum ambient SO_2 concentrations . . . 112
V-1 Northern Great Plains States, principal impact area and major cities . . . 118
V-2 Estimated annual average construction employment during construction of facilities for mining, electrical plants, and gasification plants, Campbell County, Wyoming 1975-2000 . . . 122
V-3 Coal-related employment as compared to agricultural employment in principal impact area—Montana and Wyoming 1980-2000 . . . 123
V-4 Anticipated population in the study area for each COP . . . 128
V-5 Housing requirements necessary to meet the needs of construction workers associated with a single gasification plant and powerplant . . . 134

PART I—INTRODUCTION

1-1. ***National Energy Consumption.***—America's energy consumption has grown rapidly in recent decades. In the last two decades alone (1950-1970), United States consumption of energy has doubled. The increasing population has demanded ever-expanding exploitation of energy sources for the production of manufactured goods, food, fiber, housing, and transportation. The consumption of energy has been disproportionately greater than the increase in population.

Total energy consumption has grown at a rate of 4.8 percent annually in the period 1965-1970. Much of the increase has been met by imported petroleum. In 1973, about 46 percent of the total energy consumed in the United States came from petroleum. Some 38 percent of this petroleum, or 17 percent of the total energy consumed, was imported.

This increase in energy consumption was accompanied by a decline in the real price of energy. In the electric utility industry, for example, average petroleum prices (in 1967 dollars) fell from 36.0 cents/million (cents per million) Btu[1] in 1960 to 32.0 cents/million Btu in 1969; coal from 27.3 to 25.2 cents. Average natural gas prices (1967 dollars) paid by electric utilities fell from 27.7 cents/million Btu to 24.2 cents in the 1961-1969 time period. Average composite fossil fuel prices in the electric utility industry (in 1967 dollars) decreased from 27.5 cents/million Btu in 1960 to 25.7 cents/million Btu in 1969.

The availability of relatively inexpensive energy and inverted rate structures for quantity purchases has contributed to the high energy consumption growth rates. The regulation of natural gas prices in the interstate market has been considered a deterrent to the exploration for new gas sources and to research that might speed the development of alternative energy sources. Environmental considerations have placed restrictions on the burning of coal, particularly the traditional supplies in the East and Midwest, increasing the Nation's reliance on natural gas and imports of foreign oil. The Mideast embargo on exports of oil during the winter of 1973, combined with the above-mentioned factors, led the United States to an awareness of the growing energy dilemma.

Heavy reliance on imported or domestically produced petroleum to satisfy the Nation's growing demands for energy is an uncertain possibility. There are political and economic constraints on importation of petroleum. Domestic reserves of petroleum and natural gas are limited. Hydropower is also limited. Nuclear power may make more significant contributions in the future, but its contribution has not been increasing as fast as had been expected. Solar, geothermal, theoretical nuclear fusion, and other "exotic" sources of energy are not expected to make significant contributions in the near future.

Thus, the questions are: How will the Nation supply its short- to medium-term energy requirements? To what extent will conservation of energy and increased energy efficiency reduce anticipated consumption? The focus of this report is an examination of the role coal will play in meeting future energy demands.

1-2. ***NGP Coal Resources.***—The coal deposits of the NGP (Northern Great Plains) are an important source of energy. The amount of coal that can be mined is large. There are 160 billion tons of coal in the 63-county NGP study area less than 1,000 feet below the surface which are minable with current technology. Of this amount, 80.2 billion tons are surface minable. This represents about 27 percent of our Nation's total minable coal reserve by weight and about 60 percent of the Nation's surface minable coal. A large proportion of this coal lies in thick, near-surface beds that are readily adaptable to quick and relatively inexpensive surface-mining methods. It is much less expensive to mine than deeper, "near-surface" coal located in other parts of the country. The cost of surface mining averages about one-fourth that of underground mining. The sulfur content and heat value of NGP coal is less than most competitive eastern and midwestern coals.

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[1] Btu—British thermal unit: the quantity of heat required to raise the temperature of 1 pound of water 1° F at or near 39.2° F.

Reclamation (land rehabilitation) costs per ton of coal may be less than in many other areas because of the thick beds (large tonnage/acre) and the relatively flat terrain.

The coal from the NGP may be used to supply a variety of fuel demands. It could replace a portion of the high sulfur coal which is now being burned to generate electricity in the midwest. Electric power generated at mine site plants in the NGP could be transmitted to distant load centers over the Nation's power transmission grid. NGP coal may also be converted to synthetic gas.

In assessing the prospects for expanded development of NGP coal, its economic competitiveness with coal from other areas must be considered. NGP coal shipped by unit trains to certain points in the Midwest is competitive with some coal from other areas. The costs of electric generation at the mine site, or synthetic gas production, are now high when compared to conventional usage, but costs may decrease as technology improves. Further, coal becomes more competitive as other fuel costs increase.

Environmental considerations are important. NGP coal is lower in sulfur content by weight than much eastern coal but because of its generally lower heat value, some NGP coal is still not low enough in sulfur content to be burned without special emission controls. Those NGP deposits with higher sulfur-to-Btu ratios will be less competitive with higher Btu eastern and midwestern coals that also need stack gas emission controls. Thus, coal development must be compared with accelerated development of higher Btu, low sulfur coal in Kentucky, Tennessee, and West Virginia. Successful reclamation of mined land in the arid and semiarid NGP environment is as yet unassured. Environmental standards may make some NGP coals economically unattractive or unavailable. All these uncertainties make difficult the analysis of NGP coal development problems.

Although this report concentrates on coal development in the NGP, petroleum and uranium are important energy resources that contribute to the regional and national economy. These mineral resources as well as bentonite and sand and gravel are discussed in the Mineral Resources Work Group report.

1-3. *Concerns of the People.*—People who live in the NGP express divergent opinions about coal development. Their views range from strong opposition to strong support of development. In assessing the concerns of the people of the NGP, the current use of NGP resources and lands should be recognized. A traveler in this broad, open region quickly grasps a sense of untrammeled nature. The quality generating this impression is one of the region's assets. But a casual conclusion that the openness of the NGP means emptiness is unwarranted. Human activity is manifest. The resources of the region are being used in an economy based upon agriculture, outdoor recreation, and tourism, and oil and gas extraction. The area's social, economic, and governmental structures have evolved to meet the needs of these activities.

The people of the NGP understandably express concern over the effects of expanded coal development in terms of their own interests. For instance, the ranchers and farmers of the NGP are concerned about competition for land and water. Many are concerned about the conversion of present and potential agricultural water supplies to industrial usage. Some also believe mined land cannot be reclaimed nor shallow aquifers reestablished; they conclude that mined land may not be returned to productive use. Others regard coal development as a temporary disruption of the land and seek ways of taking advantage of development in ways that will improve existing agricultural conditions.

Agriculturists are also concerned with air pollution and its impacts on range vegetation and crops. The businessmen who derive their livelihood from tourism express concern about air pollution. There is general concern that the abundant wildlife resources may be diminished or degraded and the present high quality of recreation thus impaired.

The several Indian tribes in the region ask how coal development on or near their reservations might impact their water rights, resources, and cultural values. They fear that with coal development they will lose control over their reservation coal resources and the land base that is central to the Indian way of life. They also value coal development for its job opportunities and other income to alleviate poverty.

Perhaps the deepest concerns are for the possibility of disruption of the stable economic and social patterns of the NGP. Both urban and rural residents are worried about the ability of their communities to cope with the needs of the new families that will accompany coal development. They are concerned about the impact on schools, police and welfare services, recreational facilities, sewer and water, and other community services. The business community and county government managers are uncertain over the nature, size, and timing of an increased population. They are worried about the time gap between the early need for investment in added services and the later realization of income from taxes and sales.

The more subtle concern involves the social structure of the communities. How will coal development and the resulting influx of labor and industry management change the way people live? What kind of people will the miners, construction workers, and their families be? Where will they live? What new power structures might emerge and how would they affect existing social and economic groups?

Clear air, clean water from streams and wells, a stable economy, a comfortable social structure, the familiarity of their towns, the quiet: these are things that the people of the NGP feel are threatened.

Not everyone is fearful about the effects of an expanded coal industry. There are people who view the industry as something good. They see increased coal production in terms of an expanding economic base, new jobs, better services, and broadened cultural horizons. These people are eager for development.

1.4. ***The Northern Great Plains Resource Program.***—The NGPRP (Northern Great Plains Resource Program) is a joint effort by the Federal and State governments, the Indian tribes, as well as industry, environmental groups, and other private and public organizations and individuals all of whom are concerned with the effects of coal development in the NGP. They are concerned that the Nation have an adequate supply of energy, but they wish to be assured that energy development proceeds in a way that minimizes adverse environmental and socioeconomic impacts.

The primary objective of the NGPRP is to provide information and a comprehensive analysis that will place in perspective the potential impacts of coal development and thereby assist the people of the NGP and the Nation to wisely manage the natural and human resources of this region. The NGPRP is a communication and coordination link among concerned organizations and individuals, so that they function more efficiently and effectively in dealing with the resource problems of the region.

The involvement and interest of the participants in the study are manifold. The Department of the Interior, Department of Agriculture, and the Environmental Protection Agency are responsible for such tasks as managing the Federal land and water and mineral resources, protecting the quality and quantity of the air and water, studying reclamation potential, and providing certain services. The States' responsibilities are similar; the work of the county and municipal governments is at a more local level. There is a shared concern that the Program study be as complete as time allows.

The investigations and studies of the Work Groups are in seven subject matter categories: Regional Geology; Mineral Resources; Water; Atmospheric Aspects; Surface Resources; Socio-Economic and Cultural Aspects; and National and Regional Energy Considerations.

The constitution of the Work Groups and other organizational elements of the NGPRP are shown in Appendix A.

The geographic area of the studies included 63 counties covering 91.6 million acres of Montana, Wyoming, North Dakota, South Dakota, and Nebraska. The analyses of physical resources focused on the coal fields of the Fort Union Formation, NGP region. The analyses of other resources, in several instances, covered a much larger portion of the five-state area to treat important issues and effects of coal development.

The portion of the five-state region studied by each group is referenced in each section of the report or shown on the enclosed plates. The Work Group reports were structured to generally include a regional profile section describing present conditions in the subject field of interest; a review of constraints describing the legal, institutional, and other constraints that will affect future regional energy development; and an impact analysis describing the changes which would be expected to occur as a result of each of three alternative rates of coal development. The alternatives are encompassed in the term "CDP's" (Coal Development Profiles) in this report. There are three such profiles: CDP-I, CDP-II, and CDP-III.

CDP-I reflects a "low" level of future energy development—enough to supply regional energy requirements and to honor coal export and electric power generation commitments as of mid 1973; CDP-II is an "intermediate" profile that conforms to 1973 regional energy supply projections performed by the Department of the Interior;[3] and CDP-III is a "high" profile that foresees the NGP responding to a long-range national energy "emergency." The effects of the three different rates of coal development on the environmental, social, and economic structure are estimated through the year 2000.

1-5. *Scope of Report.*—Time and data constraints have necessarily limited the scope and depth of this NGPRP study. The recognized constraints follow:

a. The focus is only on coal and the impacts of its development. (The environmental, social, and economic consequences of coal development appear to be the greatest in importance among energy resources over the next few years. The NGP has many other energy resources, which are considered in the supply and demand analysis.)

b. The primary impacts of the three CDP's are estimated as fully as possible. (Data and time did not permit comprehensive identification and analysis of most secondary impacts, such as the impact of major coal transportation use of railroads on availability of rail facilities for agricultural crop export or the impact of developing service industries in South Dakota and Nebraska.)

c. The three CDP's are hypothesized only through the year 2000. (Available data indicate that the decline of the coal industry in this area would not occur until sometime after the year 2000. Consequently, the impact of mine and other related facility closings was not identified and analyzed.)

d. Most of the Work Groups found major data gaps. (These are usually indicated in the text of this report and in the Work Group reports.)

Some of the deficiencies of this report will be addressed in future efforts of the NGPRP to close knowledge gaps.

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[3] Dupree, Walter G. and West, J. R., *United States Energy Through the Year 2000*, Department of Interior, December 1972.

PART II—THE COAL RESOURCE OF THE NORTHERN GREAT PLAINS

2-1. ***Issues.***—The NGP region has vast coal deposits. But the presence of coal does not automatically ensure that it can or will be mined. There are numerous factors that might constrain the development of the coal. For instance, the unusual ownership pattern of minerals and surface estate may prevent many tons from ever being mined. Federal and State leasing regulations may inhibit development, or environmental considerations may preclude use of large amounts of coal.

The purpose of part II is to describe the coal resource of the NGP, analyze the likelihood of its development, and identify and assess the several important issues confronting those considering development of NGP coal. Part II discusses the questions:

a. How much coal is in the NGP?

b. How much of the available coal can be economically mined?

c. How does, or how could, surface and mineral ownership patterns impede production of NGP coal?

d. Will the coal resource be large enough to meet forecasted demand if Federal coal underlaying non-Federal surface is unavailable?

e. How do the characteristics of NGP coal affect its marketability?

2-2. ***The Coal Resource.***—The total estimated coal resource in the 63-county study area (plate B-3) of Montana, North Dakota, South Dakota, and Wyoming is 1,524 billion tons.[3] Of this amount, 835 billion tons are hypothetical deposits in unmapped and unexplored areas, 529 billion tons are inferred on the basis of mapping and field studies, while the remaining 160 (rounded from 159.5) billion tons are identified sufficiently to be classed as reserve base. Reserves are defined as coal measured and known to be present by field studies and minable by current technology (this coal is not necessarily economical to extract and transport to points of use). These deposits generally include coal that is less than 1,000 feet below the surface and in beds 5 feet or more thick. This is in contrast to definition of the resource as being the total amount of coal that is thought to be in the ground. Table II-1 is a summary of these tonnages:

Table II-1—*Coal resource of the 63-county study area (billions of tons)*

160	Reserve base, measured and indicated by studies, minable
529	Inferred by studies, not considered minable
835	Hypothetical resources, unmapped and unexplored
1,524	Total resource

Source: Mineral Work Group Report and Montana Energy Advisory Council "Coal Development Information Packet," December 1974.

The 1,524 billion tons are about one-half of the Nation's total coal resource, while minable reserves of 160 billion tons (table II-1) are 37 percent (by weight) of the Nation's coal reserve base. Table II-2 presents the 160 (159.5) billion-ton coal reserve base location by State and by mining method.

The 80.2 billion tons of coal reserve base at depths amenable to surface mining are shown on plate B-3.

The 80.2 billion tons referred to in table II-2 constitute about 60 percent of the Nation's surface minable coal reserve. Not all of the 80.2 billion tons (table II-2) that are classified as being surface minable can be recovered.

Of the reserve base which is determined to be environmentally available for mining by surface methods, present technology indicates a minimum 80 percent recovery can be anticipated. The percentage of the 79.3 billion tons of coal that can be recovered by underground mining methods may be much lower. The limitations of underground mining technology and economic considerations reduce the amount that can be recovered by about 50 percent (table II-2). Although the 63-county study area encompasses nearly 92 million acres, less than 3 percent, or about 2.6 million acres (table II-3, plate B-3), are underlain by surface minable coal.

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[3] Data compiled by NGPRP from U.S. Geological Survey, U.S. Bureau of Mines, and State Geological Surveys.

Because of economic, environmental, and physical constraints, it is unlikely that all of the 2.6 million acres underlain by coal would be mined. Section 4-2, Land Resources, presents a discussion of the amount of acreage that would be disturbed for mines and plant facilities assuming three different rates of development.

Coal resources of the NGP differ in several aspects from most eastern deposits:

a. Costs of surface-mining methods are lower because of the thick seams, relatively thin overburden, and low relief of much of the land.

b. Sulfur content per Btu is thought to be lower than nearly all midwestern and most eastern coal. (Although it is not necessarily low enough to meet new source pollution standards.)

c. High ash and water contents and higher

Table II-2.—*Estimated coal reserve base of the NGP*[1]
(billions of tons)

State	Total reserves	Surface minable[2]		Underground minable[3]	
		Total	Recoverable	Total	Recoverable
Montana[4]	107.0	42.6	34.1	64.4	32.2
Wyoming	36.1	21.2	17.0	14.9	7.5
North Dakota[5]	16.0	16.0	12.8	0	0
South Dakota[5]	0.4	0.4	0.3	0	0
Total	159.5 (160)	[6] 80.2	64.2	79.3	39.7

[1] Beds 5 feet or more thick and less than 1,000 feet below surface.

[2] Beds 5 feet or more thick with a maximum of 200 feet of overburden for the thickest beds.

[3] Conventional room and pillar method.

[4] Does not include an estimated 8 billion tons strippable on the Northern Cheyenne and Crow Indian Reservations. Rawlins, J. H., "Montana in Western Coal," Coal Age, mid-April, 1973, p. 117.

[5] By definition, lignite is not included in underground reserve base.

[6] Depths shown on plate B-3.

Source: NGPRP Mineral Work Group.

Table II-3.—*Acres underlaid by surface minable coal in the NGP*

State	Acres in study area (millions)	Acres underlaid by coal (millions)
Montana	34.6	1.4
North Dakota	26.7	0.7
South Dakota	11.7	0.1
Wyoming	18.6	0.4
	91.6	2.6

Source: NGPRP Surface Work Group report.

percentages of volatile hydrocarbons reduce the Btu content per pound considerably below that of most eastern coal. (Therefore, the sulfur-to-Btu ratio rather than the sulfur-to-weight ratio must be used to compare eastern and NGP coal on a consistent basis.)

The above factors all affect the marketability of the NGP coal (sec. 3-6).

A precise assessment of the sulfur content of the coal resources in the NGP is not available. A statistically valid sampling of coal beds, in conjunction with reliable estimates of the amount of coal in each bed, is necessary to assess the ability of NGP coal to comply with the air quality control regulations embodied in the Federal NSPS (New Source Performance Standards).[4] Without such basic analytical data, only broad-brush estimates can be attempted.

Much of the published analytical data come from the U.S. Bureau of Mines. The bulk of such data is from samples of coal purchased for Government use under specifications that define the requirements in terms of heating value and composition of the coal. This probably biases the sampling. Recently, the U.S. Geological Survey and the Montana Bureau of Mines and Geology cooperatively conducted drill hole sampling of coal in portions of Wyoming and Montana. However, these data were not correlated with specific coalbeds and therefore do not define coal reserves by sulfur content. These basic data are being expanded to include bed data and are being published as open-file reports and maps by the USGS. The combining of existing data from the U.S. Bureau of Mines, USGS, individual companies, and State and other sources could conceivably constitute sufficient data for a statistically valid interpretation of reserves by sulfur content. Until such a task is undertaken, however, all other estimates of coal reserves by sulfur content cannot be considered with any degree of confidence except in the broadest of terms and then only if other assumptions are valid.

There have been some attempts at delineating the quantity of NGP coal which could meet NSPS SO_2 limitations. A study at the University of Illinois[5] indicates that the NGP coal contains a much higher effective sulfur content than has been commonly understood because western coals are lower in heating value than their counterparts in the east. For reasons cited above the study does not reveal the amount of NGP coal that would meet NSPS. An analysis by the Sierra Club[6] attempts to determine the relative sulfur content of NGP coal base from drill hole data in the Powder River Basin of Wyoming.[7] These data, however, lack the necessary coalbed correlation for such an assessment.

Studies of SO_2 emission from the burning of coal such as those mentioned above have usually assumed 100 percent conversion of the sulfur in the coal to SO_2 emissions out of the stack. This is not necessarily true for NGP coals. This subject is further discussed in section 3-6.

The above-mentioned reports point up the need to appraise different coals on a comparable Btu basis for determination of effective sulfur contents and to make some qualification on the amount of NGP coals able to meet SO_2 standards.

2-3. Ownership Patterns of the Surface and Mineral Estate.—Starting with the Homestead Act of 1862 and successive legislation, the Federal Government granted parcels of land to anyone willing to work them. The original grants transferred both the surface and mineral rights to the land, but eventually the Federal Government withheld rights to known reserves of coal and other minerals underlying homestead lands. These acts and grants contributed to mixed surface and mineral ownership patterns (plates 10, 11, 12, 13, and 14). The Federal Government controls rights to the coal and other minerals on many acres for which it has no surface rights. In the portions of Montana, North Dakota, and Wyoming included in the NGP study area, the Federal Government controls 39 percent of the total mineral estate acreage (plates B7a and B7b). More than 60 percent of the estimated total coal resource in the study area is located on the 39 percent of the mineral estate controlled by the Federal Government.[8] This 60 percent represents about 96 billion tons of the coal reserve (160 billion tons times 60 percent).

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[4] NSPS are standards for emissions from stationary sources which have been developed to assure compliance with national ambient air quality standards. Emissions covered are SO_2, NO_x, hydrocarbons, photochemical oxidants, CO and particulates.

[5] Rieber, Michael, "Low Sulfur Coal, A Revision of Reserve and Supply Estimates," CAC doc No. 88, Center for Advanced Computation, University of Illinois, 1973, 56 pp.

[6] Curry, R. and Anderson, E., "Some Western Coal Sulfur Problems," Sierra Club, San Francisco, California, 1974, 8 pp.

[7] U.S. Geological Survey and Montana Bureau of Mines and Geology, "Preliminary Report of Coal Drill Hole Data and Chemical Analyses of Coal Beds in Campbell County, Wyoming," USGS Open-file Report, 1974, 241 pp.

Various railroad grants also contribute to the mixed ownership pattern of the study area. These were grants of considerable land, including coal rights, adjoining the railroad rights-of-way. As an example, the Northern Pacific Railroad was given odd-numbered sections (one section equals 1 square mile) in a checkerboard pattern for a distance of 40 miles on both sides of the right-of-way (plate B-7b). The result is a mix of Federal, railroad, and the private land ownership on either side of the right-of-way. Table II-4 compares by percentage the surface and mineral ownerships in the NGP study area.

The scattered and mixed ownership patterns in the NGP complicate coal development in several ways. A reasonably large contiguous area is required to make mining economically feasible. Rights-of-way for access roads and railroads may be required. Where gasification plants or mine-mouth-generating operations are planned, land for plant sites and rights-of-way for powerlines and pipelines are necessary.

To combine rights to enough land having adequate coal reserves to support an economic mining unit and obtain the necessary rights-of-way, a potential coal developer may be required to deal with many private landowners as well as the Indian tribes and Federal and State governments. As stated previously, the non-Federal owners may or may not possess mineral rights on areas where they own surface rights; conversely, the

Table II-4.—*Surface and mineral ownership of study area by owner and State*

State (NGPRP study portion)	Type of ownership	Owner (in percent of total)				Total acres (millions)
		Federal	Indian	County municipal and private[a]	State	
Montana	Surface	17.0	8.2	69.0	5.8	34.6
	Mineral	33.0	7.9	53.3	5.8	
North Dakota	Surface	7.3	2.7	87.5	2.5	26.7
	Mineral	20.3	3.8	73.4	2.5	
South Dakota	Surface	5.6	16.6	71.9	5.9	11.7
	Mineral	12.1	18.0	57.0	12.9	
Wyoming	Surface	22.9	0	68.5	8.6	18.6
	Mineral	42.6	0	48.7	8.7	
Total NGP	Surface	13.9	6.0	74.7	5.4	91.6
	Mineral	28.6	6.4	58.7	6.3	

Source: NGPRP Surface Work Group report.

[a] Includes substantial surface and mineral rights held by the Burlington-Northern Railroad.

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[8] U.S. Department of the Interior, Bureau of Land Management.

Federal Government often owns the mineral rights but not the surface rights.

The Federal Government has leased mineral rights on some land where the surface rights are in private ownership. A procedure for securing surface rights to land on which the mineral rights are under Federal lease was included in the Stockraising Homestead Act of 1916. This Act provided that if the surface owner is agreeable to selling or leasing his surface rights, the lessee and the surface owner must both agree to the amount of compensation the surface owner will receive. Such an agreement may involve the sale of the land, compensation for damages to property that might occur, or a periodic payment for the loss of income from land taken out of crop or grazing use. If the surface owner and the lessee cannot reach agreement, the lessee submits a plan and posts a bond (not less than $1,000) to the Secretary of the Interior's representative[9] to insure payment of compensation for damages. The Secretary's representative then reviews the plan and the amount of bond. He can either disapprove and return the plan to the lessee for revision or he can approve the plan and so notify the surface owner. The surface owner then has 30 days to appeal through the courts.

As defined by the Homestead Act of 1916, compensation is limited to those things that can be easily evaluated—fair market value, replacement of a building or compensation for crops out of cultivation. But the Act does not cover compensation for intangibles such as alteration of lifestyle. Determining the appropriate monetary consideration to compensate a rancher for moving his family off a home ranch is a difficult problem. How can a monetary value be readily placed upon such an intangible? What compensation should be paid to a farmer for his dislocation? How much is personal independence worth to a man? All these questions of value are raised when surface owners are asked to relinquish all or part of their farms and ranches so that the coal resource can be developed.

The 93rd Congress enacted a bill relating to the surface mining of coal (S. 425) which contained specific provisions with respect to the surface mining of Federal coal deposits in areas where the surface rights are not owned by the United States. Although the President pocket vetoed this bill, it seems reasonable to assume that a similar bill insofar as the provisions for protection of private surface owners will be passed by the 94th Congress.

In this bill the Secretary of Interior was directed in his discretion and to the maximum extent practicable to refrain from leasing coal deposits for development by methods other than underground mining techniques and prohibited the consummation of any lease until the surface owner has given his written consent and the applicant for the lease had agreed to post an adequate bond or to pay to the United States the money value of the surface owner's interest which is then received by the surface owner. The value of the surface owner's interest was to be determined by appraisers who would first establish the fair market value of the surface estate to which would then be added factors to reflect the loss of income to the surface owners; the cost to the surface owners of relocation; the cost to the surface owners from the loss of livestock, crops, water, or other improvements; and any other damage reasonably anticipated. In addition the surface owner could be awarded a bonus not to exceed $100 per acre. For the purpose of that bill a surface owner was defined as one who had title to the land as of December 3, 1974, and who had for the last 3 years his principal place of residence on the land or who had personally conducted farming or ranching operations upon the land or who had received directly a significant portion of his income from such farming or ranching on the land. A surface owner who does not meet this requirement would have still been entitled to compensation under the Homestead Act of 1916.

To better understand how this bill, or a similar one, may affect coal development, an examination of current *Federal leases* in the NGP was made. It showed that two-thirds of the leased acres (including 65 percent of leased coal) are overlain by privately owned surface rights. Almost all leases in Montana and North Dakota and about 42 percent of the coal under lease in Wyoming are under privately owned surface land. This is about 6.5 billion of the 9.8

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[9] Bureau of Land Management State Director.

billion tons currently under lease. A further evaluation was made of approximately 900,000 acres in the Decker-Birney area in Montana.[10] This region contains about 15.9 billion tons of recoverable surface minable coal. The Federal Government owns both surface and mineral rights on about 79,000 of the 900,000 acres. Underlaying the 79,000 BLM acres are about 1.4 billion tons of recoverable surface minable reserves of coal. The BLM also administers the mineral rights, but not the surface rights, to lands that contain an additional 9.73 billion tons of recoverable strippable coal reserves. If S. 425 or a similar bill were to become law, this 9.73 billion tons or 61 percent of the 15.9 billion tons now recoverable could not be developed without the consent of the surface owner. This 61 percent does not include any coal that could legally be developed but was not in an economic mining unit.

This analysis has dealt with Federal coal, some 60 percent of the reserve. The remaining non-Federal reserve would not be directly affected by provisions of the bill except where intermingled ownership would require coordinated development of Federal and non-Federal coal.

No study has been performed of the total number of Federal coal land acres under private surface ownership in the NGP study area portion of these States; however, table II-5 below presents these data on a statewide basis ownership for the entire NGP States.

2-4. *Federal and Other Coal Leases.*—At present (1974) there are 128 Federal coal leases in Montana, North Dakota, and Wyoming and none in South Dakota (plates B7a and B7b). These 128 leases include about 252,000 acres and represent a minable reserve of about 9.8 billion tons of coal (table II-6).

There are no firm estimates of how much of the State and private coal reserve is under lease or otherwise controlled by coal developers. A recent study by two students at the University of Wisconsin, Russell Boulding and Francis Cherry[11] provides an estimate of the amount of coal acreage now under lease in the NGP area. It was compiled from numerous sources such as Federal, State, environmental groups, and other private publications. The Indian data were supplemented with Bureau of Indian Affairs information. Table II-7 summarizes the information.

Further, the Montana Energy Advisory Council[12] recently published information showing that in 12 eastern Montana counties

Table II-5.—*Federal mineral and surface ownership*

State	Total acres of Federal minerals (millions)	Federal mineral acres under non-Federal surface ownership (millions)	Percent of Federal mineral acres under non-Federal ownership
Montana	18.8	10.7	56.9
North Dakota	4.9	4.8	98.0
South Dakota	1.0	0.5	50.0
Wyoming	29.3	11.8	40.3
	54.0	27.8	52.9

Source: U.S. Department of the Interior, Bureau of Land Management.

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[10] The area was studied by the U.S. Department of the Interior, Bureau of Land Management, and the Forest Service, U.S. Department of Agriculture, and the State of Montana. It is the most intensively studied area in the NGP. Its coal reserves were evaluated by the NGPRP to determine the possible implications of S. 425.

[11] Boulding, Russell and Cherry, Francis. "Coal Leasing Policy in the Northern Plains: The Complexities of Dispersed Ownership," University of Wisconsin, 1974.

[12] State of Montana, Montana Energy Advisory Council, "Coal Development Information Packet," December 1974.

Table II-6.—*Federal coal leases in the NGP States*

State	Number of leases	Acres under lease (thousands)	Minable reserves under lease (billions)
Montana	17	36	1.1
North Dakota	19	16	0.3
South Dakota	0	0	0.0
Wyoming	92	200	8.4
Total	128	252	[a]9.8

[a] Includes 0.6 billion tons of underground minable coal in Wyoming; the remaining 9.2 billion tons are considered surface minable.

Source: U.S. Department of the Interior, U.S. Geological Survey.

Table II-7.—*Federal, State, private, and Indian acres under lease for coal in NGP States (in thousands of acres)*[5]

State	Federal acres under lease[1]	State acres under lease	Private acres under lease	Indian acres under lease
Montana	36	[2]58	334	[2]91
North Dakota	16	[3]6	1,000	0
South Dakota	0	No data	No data	0
Wyoming	200	[3]1,156	[4]60	0
Total	252	1,220	1,394	91

[1] From U.S. Department of the Interior, Bureau of Land Management.

[2] Boulding-Cherry study.

[3] Annual Report 1974, State Land Office.

[4] NGPRP estimate.

[5] Acres may not be underlaid by surface minable coal.

over 165,000 acres of private coal have been leased and a total of over a million acres of privately owned surface and/or coal has been obligated to energy interests. The total includes leases, lease options, exploration agreements with options to lease, and a variety of surface agreements. No surface or mineral holdings of the Burlington Northern Railroad were included.

It is estimated that there were [illegible] to 3.5 billion tons of coal under lease on the Northern Cheyenne and Crow Indian Reservations in Montana. The status of these Indian leases is not clear. As a result of a recent Supreme Court decision, the Northern Cheyenne Tribe has requested the Secretary of Interior to cancel all existing leases and prospecting permits pertaining to their reservation. The status of these leases is in question.

2-5. *Mining Methods. a. Longwall Mining.*—The longwall method of underground mining was developed in Europe and is now being used to mine coal at depths to 4,000 feet. Over 60 underground coal operations in the United States use the longwall system in coalbeds ranging in thickness from 4 to 8 feet, including a few operations in Colorado and Utah.

In conventional longwall mining, blocks of coal up to 600 feet wide and 3,500 feet long are isolated by conventional mining methods, leaving coal pillars to support the entries separating the blocks. Mining then commences on the end of a block and the block is mined with up to 85 or 90 percent coal recovery. Mining equipment consists of a number of self-advancing hydraulic roof supports, which provide a steel canopy over the miners, a coal conveying system, and a mining machine. The mining machine rides on the top edges of the conveyor system which stretches the width of the coal block. The mining machine traverses the coal face, removing coal, and the mined coal falls into the conveyor. As the coal is mined, the roof supports advance, moving the conveyor and mining machine forward against the coal face and allowing the roof to collapse into the mined-out area.

b. *Underground Versus Surface Mining*.—The mining technology that is being used for coal energy development in the NGP is strip mining; few developers have shown an interest in underground mining. Underground mining, however, has found advocates in the NGP who see it as a method of retrieving the region's coal without disturbing the earth's surface and others see it as being necessary to provide adequate amounts of coal for long-term energy needs.

Table II-8 presents a comparison in broad terms of the economics, environmental impacts, and relative safety of underground and surface mining techniques. From a strictly economic standpoint, the underground mining of coal in the NGP would be in a weak competitive position. Compared to surface mining, capital investments are higher, specialized labor is more scarce, and productivity per man is lower. Thus, the cost of underground mining in the NGP can be seen as being considerably higher than surface mining.

The lower worker productivity of underground mining would increase the number of workers needed to produce a given amount of coal. It would take 8 to 10 times as many workers to produce a given amount of coal by conventional underground room-and-pillar methods and 3 to 4 times as many to produce the same amount by longwall[11] methods (where these mining methods are feasible) as are needed in a surface mining operation. Further, the specialized skills required for underground mining would increase the need for mine workers from outside the region, thereby compounding concerns for population growth in the NGP. The proportionately larger number of workers with the associated disproportionate growth in population is probably the most significant difference between underground and surface mining in the NGP in terms of environmental impact assuming surface-mined land can and will be rehabilitated.

Underground mining has been inferior to surface mining from a worker safety standpoint. New mine safety regulations will improve the record for underground work but at considerable expense. Whether the improvement will make conventional underground mining as safe as surface mining is questionable.

Conventional room-and-pillar mining, the usual mode of underground mining in the United States, is generally inferior to surface mining in terms of resource conservation. Room-and-pillar mining cannot be used to mine thick seams without low recovery ratios, even where pillars are retrieved. Modern equipment capability and domestic mining practice effectively limit face heights to 10 feet or less. It is conceivable under favorable circumstances to mine coal greater than 10 feet thick by recovering the coal in layers. However, this presents severe problems in roof support to protect men and equipment. Pillars of coal left unmined to support the roof must be greatly increased in size, which in turn leads to decreased coal recovery. The most adverse environmental impact of room-and-pillar mining is irregular subsidence. When it occurs, damage includes surface fissures, sinkholes, cave-ins, and other irregular lowering of the land. Vertical subsidence combined with horizontal displacement alters surface and ground-water drainage patterns permitting water and air to enter the underground workings. The increased oxygen may lead to

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[11] Longwall mining is briefly described in section 3.5(b).

Table II-8.—*Comparison of surface and underground mining*

Item	Surface mining	Underground mining
1. Environmental impact		
a. Air	Considerable dust problem	Potential pollution of air and waste of coal from uncontrolled underground burning; dust problem from coal-refuse pile
b. Water	Possibly increased water infiltration and retention in reclaimed, disturbed areas; disturbed shallow aquifers; leaching from spoil piles	Altered drainage systems, a possible result of subsidence; leaching from above-ground, coal-refuse banks
c. Land surface	Insufficient fill material for thick, near-surface seams; topographic reclamation not difficult in some areas of NGP; some erosion problems from high winds, storms; revegetation a problem in the more arid areas or drought years	Important surface subsidence problems can be partly controlled but not eliminated by longwall mining where feasible. Subsidence generally reduced or eliminated by mining at considerable depth
2. Time lag for delivery of major equipment	6 years	3 years
3. Time lag to reach full production	1-3 years[1]	3-5 years
4. Capital requirements	$35 million for 9-million-ton/year mines	$75 million for two 4.5-million-ton/year mines, conventional room and pillar
5. Coal prices at mine, 1973 average[2]	$[illegible].11/ton (U.S.)[4] $3.02/ton (NGP)[4]	$10.84/ton (U.S.) for conventional room and pillar
6. Average labor productivity	104 tons/man/shift[3]	12 tons/man/shift for conventional room and pillar;[3] 34 tons/man/shift for advanced European longwall[6]
7. Labor availability	Good, requires general construction experience	Poor, requires specialized training, work has less appeal

Table II-8.—*Comparison of surface and underground mining*—Continued

Item	Surface mining	Underground mining
8. Safety-fatal injuries per million short tons, 1970	0.12	0.53 conventional room and pillar; longwall may be significantly less
Nonfatal injuries per million short tons, 1970	4.94	25.8 conventional room and pillar; longwall may be significantly more
9. Resource conservation—coal recovery	80-95 percent (NGP)	Thin seams—40-60 percent (room and pillar), up to 85 percent (retrieving pillars if feasible), up to 90 percent (longwall, if feasible) Thick seams—very low conventional room and pillar; higher for longwall, if feasible

underground burning, causing pollution of air and water by the products of combustion, as well as waste of coal. Rehabilitation and use of subsiding land is difficult, if not impossible, because the subsidence continues indefinitely at irregular intervals. Although techniques such as backfilling of mine cavities can reduce subsidence, they are usually uneconomical remedies.

Subsidence can be controlled in some cases. When mining relatively shallow seams by conventional methods, removal of the pillars encourages subsidence to occur more quickly and uniformly, leaving only the disturbed strata to become compacted. Compaction of the disturbed strata must occur to achieve a stable condition. In favorable geologic areas, controlled subsidence leaves the surface relatively intact and eliminates need for major land rehabilitation. Modern longwall mining, a technique developed in Europe and used in about 3 percent of the mines in the United States, generally achieves controlled subsidence and is being used to mine thick seams of coal

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[1] Whereas an underground mine is dependent upon highly specialized equipment, a surface mine can be brought to full production using conventional construction-type equipment. If used equipment is unavailable, delivery of scrapers, dozers, and wheel loaders is approximately 9 to 15 months in comparison to several years for draglines and shovels. In addition to startup use, "surface mine" construction equipment can often be used for sustained, full-scale production, particularly in the NGP. A recent investment analysis of scraper and dragline mining systems by Caterpillar Tractor Company ("Caterpillar Western Coal Mining Systems") compared the two systems for production of 7.5 million tons of coal per year from a 75-foot coalbed under 75 feet of overburden. The scraper system compared quite favorably in cost with the dragline system, as well as being more mobile and flexible.

[2] Average of present high productive mines in NGP. This may increase to 170-250 tons/man-day in the future.

[3] National average. Would be greater with new large mines using latest technology.

[4] Production rate from advanced European longwall techniques. This may be improved if applied on large scale in the United States.

(comparable to those of the NGP) with high recovery levels and with minimum surface disturbance.

A recent analysis[14] on nonfatal coal mining accidents in longwall operations shows that this mining method has twice the frequency rate of disabling injuries as other more conventional methods, although both the severity rates and mean number of disabling days lost were comparable. Mortalities were not delineated because of insufficient data.

The cost of longwall mining is comparable to conventional room-and-pillar mining. It is doubtful, though, that longwall mining, or any other type of underground mining, can be used successfully to mine thick coal seams with thin overburden. The thin overburden is not likely to remain intact with removal of the coal. Recognition of this fact may eliminate the shallower NGP coals as candidates for conventional underground or longwall mining, unless a substantial technical breakthrough occurs. The extent of surface damage that would be caused by longwall mining in deeper beds of the NGP is unknown at present and firm conclusions must await further research. Underground mining of deep seams by either longwall or conventional methods could reduce surface subsidence significantly, if not almost totally. As the overburden is undermined, it fractures and increases in volume. Experience shows that relatively deep seams could possibly be mined without significant surface subsidence, because the fracturing starts in the lower part of the overburden and the fractured material fills the cavity before the upper part of the overburden is affected. The fractures themselves do not usually extend to the surface.

The reserves of both shallow surface-minable coal and deep, subsurface-minable coal are sufficient for either source to support production at high rates for several decades. The "economically recoverable"[15] surface minable coal reserve is about 64 billion tons. Although no study has been made of the amount of coal that could be economically extracted by the longwall method, assuming it to be feasible in the NGP, the total amount of coal that could be extracted would probably increase. If coal remains a basic energy source for a long period of time, then underground mining by all known methods will eventually be necessary. It seems doubtful, however, that underground mining will supplant surface mining in the near future in the NGP unless unforeseen land rehabilitation problems occur with the latter or significant technological advances are made in longwall mining.

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[14] Informal communication with MESA's Health and Safety Analysis Center, Denver, Colorado, concerning report now in review stage titled "Comparison of the Safety Records Between Longwall and Other Underground Methods of Mining Coal" by Oscar R. Fike.

[15] Economically recoverable: That part of the coal reserve that can be extracted in such a fashion as to be competitive with coal from other areas. This does not include the cost of transporting which, when added to the cost of extraction, may eliminate it from being competitive in the regional market with coals from other areas.

PART III.—ENERGY DEVELOPMENT IN THE NGP

3-1. *Introduction.*—Although 63 counties in four of the NGP States contain 37 percent of the Nation's total coal reserve, coal production in the NGP has never been proportional to the size of these reserves. Even with recent growth, NGP production accounted for only 33 million tons or 5.5 percent of national production in 1973 (table III-1). The reason for this disparity is that the major use of coal in the United States is to fuel electric generating plants and the NGP coal fields are much more distant from most of these plants than are the eastern and midwestern fields. The plants are concentrated in eastern and midwestern power load centers. Even with the greater production cost per ton of eastern and midwestern coal (see table III-2), the higher delivered price per Btu at major load centers has kept NGP coal at a competitive disadvantage.

Until recently coal has been at an economic disadvantage with the inexpensive petroleum and natural gas that have been available in the postwar period. In 1947, coal provided 15.8 quadrillion Btu's of energy for consumption in the United States. This was 47.9 percent of total U.S. energy consumption. In 1973, coal provided only 13.5 quadrillion Btu's of energy. This was only 17.9 percent of consumption.

The market for coal in general, and low sulfur coal in particular, has improved

Table III-1.—*Annual production of coal in NGP States (1973)*

State	NGP production in million tons	Percent of total U.S. production
Montana	11	1.7
North Dakota	8	1.4
Wyoming	14	2.4
South Dakota	0	0
Total NGP	33	5.5
Total all States	590	100.0

Table III-2.—*Reported coal selling price at mine—1973*

State	Average selling price f.o.b. mine			
	Strip mined		Underground mined	
	Dollars per ton[1]	Cents per million Btu[2]	Dollars per ton[1]	Cents per million Btu[2]
Montana	2.82	15.7		
North Dakota	2.07	15.2		
Wyoming	4.11	21.3	7.07	37.6
West Virginia	8.58	30.6	12.24	43.7

[1] U.S. Bureau of Mines, Mineral Industry Surveys—"Coal, Bituminous and Lignites, 1973," dated January 4, 1975.

[2] Assumed 9,000 Btu/lb (as received) for Montana coal; 6,800 Btu/lb for North Dakota coal; 9,400 Btu/lb for Wyoming coal; and 14,000 Btu/lb for West Virginia coal.

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markedly in the past few years. The demand for low sulfur fuels created by the Clean Air Act of 1970 has put a premium on NGP coal and expanded its market area. The Mideast oil embargo, besides demonstrating the vulnerability of foreign energy supplies, created outright fuel shortages that eliminated price as a factor for marginal increments of supply in some markets. The greatly increased prices of foreign and domestic oil have caused concurrent rises in the market price of coal, increasing the distance NGP coal may be profitably shipped.

Because of the increasing national demand for energy and the competitive position of NGP coal, there is strong pressure to move ahead with massive development of NGP coal. The purpose of part III is to focus on the renewed interest in NGP coal, specifically:

a. Aspects of national energy consumption affecting production of coal from the NGP region.

b. Other energy sources as alternatives to NGP coal.

c. Characteristics of NGP coal that are advantageous or disadvantageous in helping to fulfill the national energy requirement.

d. Effects of energy conservation on the demand for NGP coal.

e. Effects of Federal and State policy on NGP coal production and development.

3-2. ***National Energy Consumption Forecast.***—During the period 1947-1973, energy consumption increased at an average annual rate of about 3.2 percent, growing from 33.0 quadrillion Btu's in 1947 to 75.6 quadrillion Btu's in 1973. For the 5-year period 1965-1970, the growth rate was 4.8 percent; for 1972 and 1973, the rate was 4.9 percent.

A 1972 Department of the Interior report[18] predicts that, without energy conservation and with an increasing percentage of fossil fuel being consumed for electric power generation, national energy consumption will increase from 75.6 quadrillion Btu's in 1973 to 191.9 quadrillion Btu's in 2000—an annual growth rate of 3.6 percent. During this time, per capita energy consumption would almost double going from 358.1 million Btu's annually in 1973 to 686.1 million Btu's in 2000.

Figure III-1 illustrates the forecasted increase in U.S. energy consumption and the expected energy sources for this increase. The 1972 Department of the Interior forecast assumes, among other things, that:

a. The national population will grow at a rate of 1 percent/year. (The current rate of population growth is estimated to be 0.7 percent/year.)

b. Economic growth will be sustained at about 4.0 percent/year from 1980 to 2000 (4.3 percent through 1980). (There was no real growth in the economy during 1974 and most recent forecasts indicate slow recovery to rates similar to the 1972 forecast.)

c. Growth in industrial production would be 5 percent/year to 1980 and 4.4 percent/year thereafter.

Supply limitations for fuels were explicitly considered in the above forecast.

The 1972 forecast was essentially an extrapolation of historic trends based on a knowledge of how the various sectors of the economy use energy and how these sectors were growing. The forecast did not deal

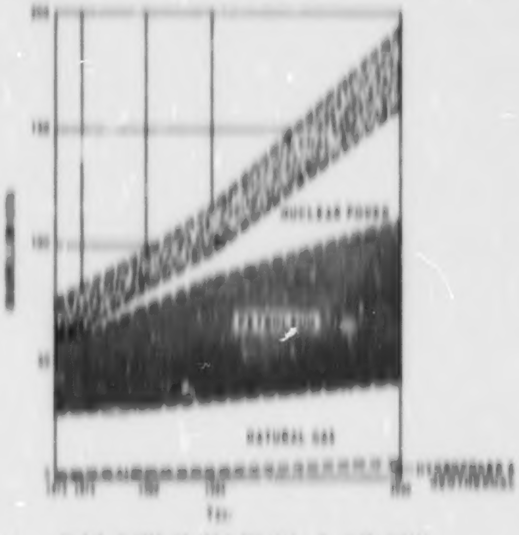

Figure III-1. U.S. energy consumption by major source.

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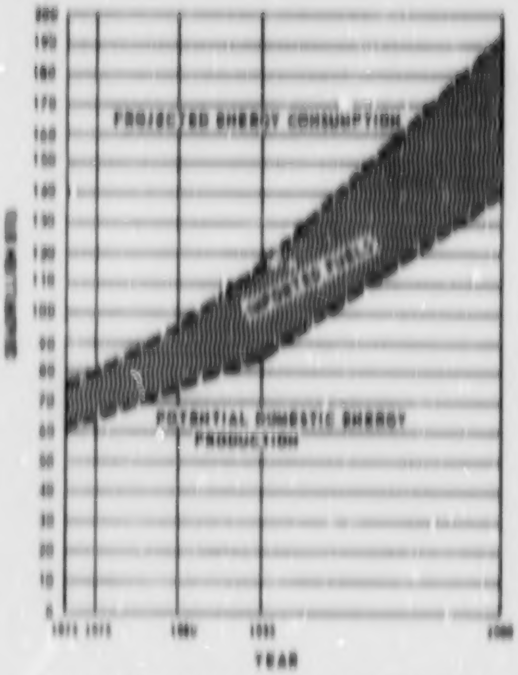
[18] Op. cit., p. 4.

explicitly with the effect of price changes on the demand and supply of energy resources. Consequently, it does not recognize energy savings or supply increases that could result from persistent increases in energy prices. Higher energy prices cause energy users to reduce energy consumption while encouraging energy producers to produce more energy. When the effects of this price-supply relationship are weighed with the conclusion of a continued high growth rate of both the economy and population, the forecast might be viewed as an overestimate of future energy consumption. It should be noted that there is no infallible method of accurately predicting the level of energy consumption 25 years into the future. Projections beyond the next quarter century would be highly speculative; nevertheless, it should be recognized that consumption may continue to grow after the year 2000 placing increased demands on NGP resources.

Others[17] have suggested lower growth rates for energy consumption than those used in this study (see conservation discussion, sec. 3-4). Nonetheless, the Interior forecast serves as a useful benchmark against which to gage the sufficiency of energy supplies and the pressure for exploitation of coal resources, both nationally and in the NGP region.

3-3. The Need for Additional Energy Supplies.—According to West and Dupree[18] the U.S. consumption of imported fuels in the year 2000 was projected to approximate two-thirds of the total energy consumption in 1973. Figure III-2 illustrates the projected role of imported fuels in future U.S. energy consumption. Figures III-3 through III-6 illustrate the forecasted production and consumption of the four major sources of U.S. energy. The projected dramatic rise in production of nuclear power from 853 trillion Btu's in 1973 to 49.2 quadrillion Btu's in 2000 illustrates the increasingly important role this energy source is expected to play. Nuclear energy and coal were the only domestic sources projected to make significant additional contributions. Domestic coal production (fig. III-4), as forecast by Dupree and West,[19] is projected to more than double in the next three decades, contributing 34 quadrillion Btu's to the national energy supply by the year 2000. On the other hand, domestic supplies of petroleum and natural gas are generally projected to be very limited, with total oil production projected to decline and gas production to stabilize. The National Petroleum Council[20] predicts that U.S. gas production under the most favorable circumstances *could* increase by 50 percent by 1985, but, at the same time, the differential between national demand and domestic production would double.



SOURCE: DUPREE, WALTER G. AND WEST, J. A., UNITED STATES ENERGY THROUGH THE YEAR 2000, DEPARTMENT OF THE INTERIOR, DECEMBER 1972

Figure III-2. U.S. potential energy production/consumption.

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[17] See, for example, the NSF-RANN study done by Chapman, Tyrrell, and Mount as summarized in *Science*, vol. 178, No. 4062 (17 Nov. 1972) pp. 703-708.

[18] Op. cit., p. 8.

[19] Op. cit., p. 4.

[20] "U.S. Energy Outlook," National Petroleum Council, December 1972.

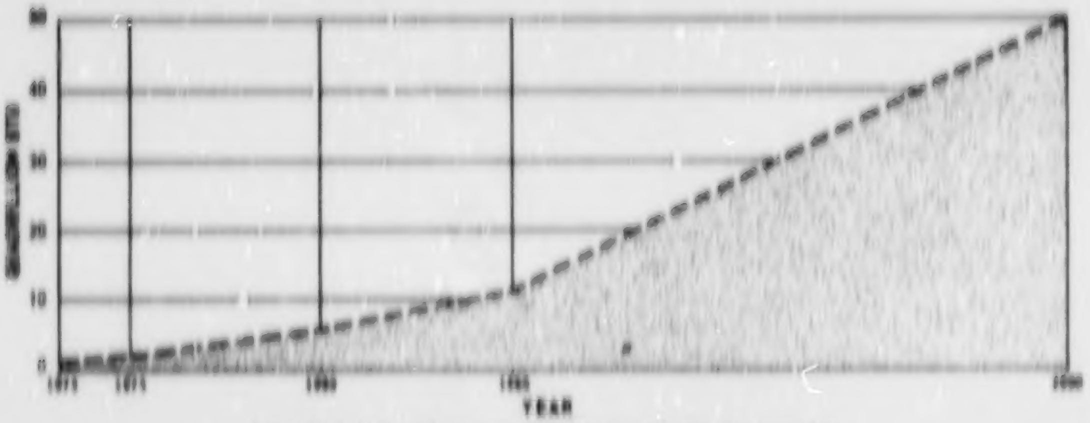
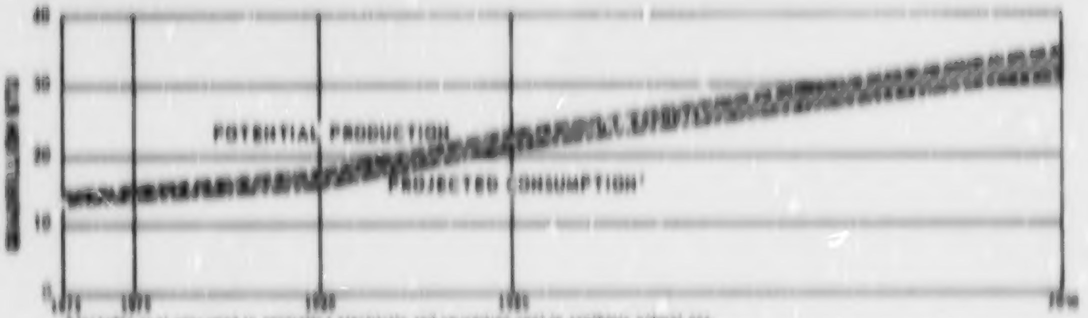


Figure III-3. U.S. nuclear-powered electricity production/consumption.



¹ Includes coal consumed in generating electricity and converting coal to synthetic natural gas.

Figure III-4. U.S. coal production and consumption.

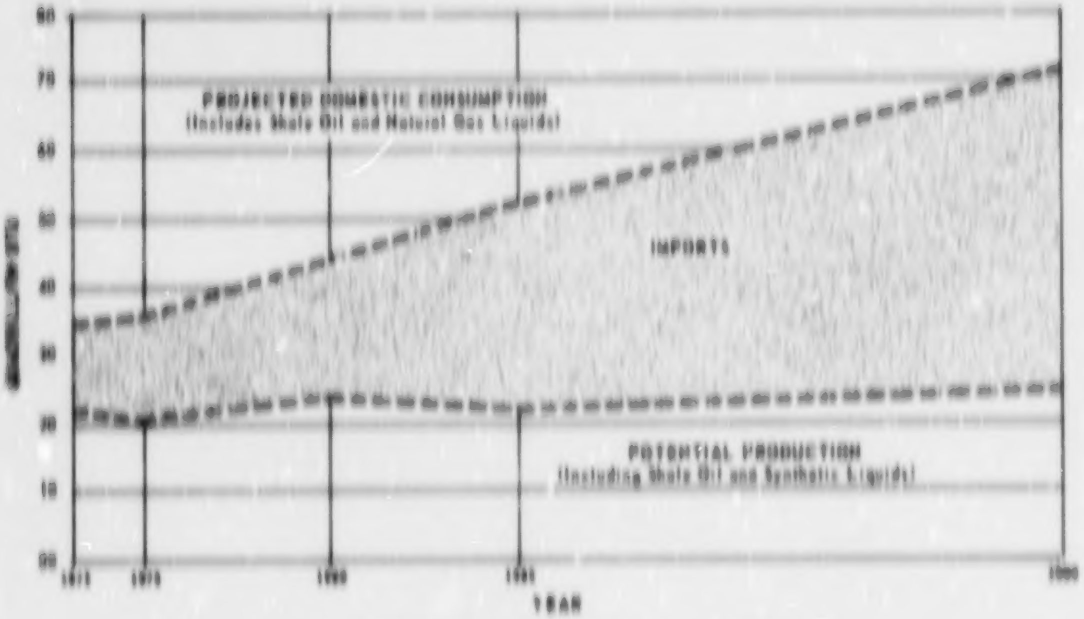


Figure III-5. U.S. petroleum production and consumption.

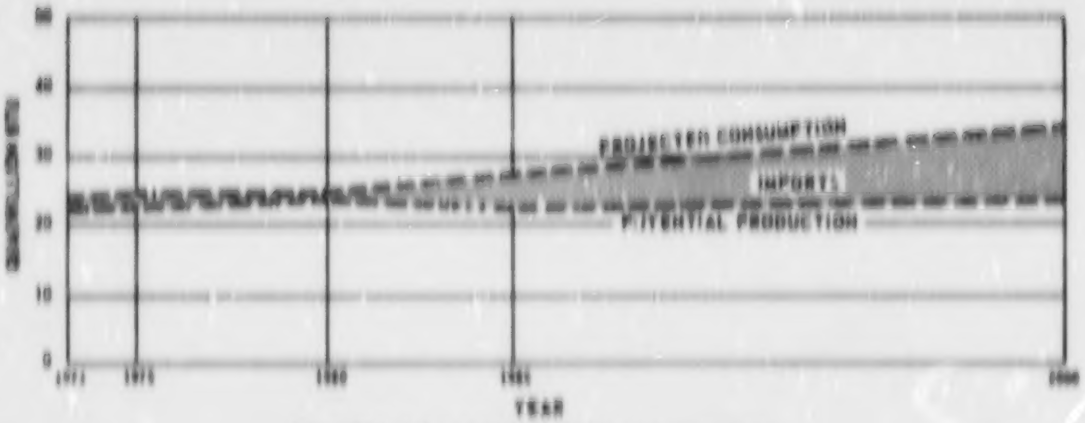


Figure III-6. U.S. natural gas production and consumption.

Although there will be incremental increases in geothermal, solar, and hydroelectric energy production, their total contribution is relatively insignificant when compared to the total estimated demand (fig. III-1).

In 1973, the United States relied mainly upon petroleum and natural gas for energy. Table III-3 shows the sources of our present energy supply.

With the higher prices recently attained by petroleum and natural gas, increased levels of exploration can be expected. Additional discoveries are expected on the Outer Continental Shelf both on current or future leases. The Department of the Interior, however, estimates that domestic oil production, including Alaskan production and shale oil, will increase from 21.7 quadrillion Btu's in 1973 to only 23.8 quadrillion Btu's in 2000. Production from the contiguous 48 States, including offshore areas but excluding shale, is projected to decline from 21.7 quadrillion Btu's to 16.3 quadrillion Btu's (see table III-4 and fig. III-5).

Natural gas prices in interstate commerce are regulated and have been held to low levels that may have discouraged exploration. At the moment, a partial deregulation—or at least a series of allowable price increases—is taking place, and general price increases are anticipated to continue. These increases are expected to stimulate exploration for new

Table III-3.—*U.S. energy sources, 1973*

Source	Total domestic and imported		Imported only	
	Quadrillion Btu	Percent of energy consumption	Quadrillion Btu	Percent of energy consumption
Petroleum	34.7	45.9	13.0	17.2
Natural gas	23.6	31.2	1.1	1.5
Coal	13.5	17.9	*	*
Hydropower and geothermal	2.9	3.9	0	0
Nuclear	0.8	1.1	0	0
Total	75.6	100.0	14.1	18.7

*The United States is a net exporter of coal.

Table III-4.—*Petroleum sources (units in quadrillion Btu)*

	1973	1985	2000
Domestic supply			
Conterminous 48 states	*21.7	18.2	16.3
Alaskan north slope	—	4.1	3.4
Synthetic liquids (shale oil)		0.5	4.2
Total domestic supply	21.7	22.8	*23.8

*Item does not add because of rounding.

domestic sources of natural gas with additional production from new sources. Nevertheless, the Department of the Interior estimates that domestic natural gas production will remain at about 22 quadrillion Btu's through the year 2000 (see fig. III-6).

The combined production of domestic petroleum and natural gas is estimated to increase from about 44.2 quadrillion Btu's to 46.3 quadrillion Btu's between 1973 and 2000, *including* Alaskan oil and shale oil. This represented 58.5 percent of the U.S. energy consumption in 1973 but would be only 24.6 percent in 2000 according to projections. The significance of this is that neither domestic petroleum nor natural gas can be expected to meet the increases in demand for energy through the year 2000.

These statistics show that to meet the projected increase in energy demand by 2000 without major conservation efforts, the United States will have to obtain as much as 122.7 quadrillion Btu's/year from oil and natural gas imports and from increased nuclear power and coal production. The Department of the Interior's projection forecasts a Btu supply as follows:

Oil imports will be at a level of 47.5 quadrillion Btu's
Nuclear power will be increased by 46.4 quadrillion Btu's
Coal will be increased by 17.9 quadrillion Btu's
Natural gas imports will be at a level of 10.9 quadrillion Btu's

If U.S. energy consumption were to continue to follow the current pattern of heavy reliance upon petroleum and natural gas, even higher levels of imports than forecasted would be necessary. Such heavy dependence upon imported energy could subject the United States to political pressures which may be unacceptable, as well as expose the United States to a potentially serious and sudden energy shortage if the foreign supply was interrupted.

The above analysis assumes the prices for petroleum and natural gas existing in 1972. The Project Independence analysis carried out by the Federal Energy Administration estimates that with petroleum at $11/barrel and natural gas at $1/thousand cubic feet, the United States could be producing as much as 8 additional million barrels/day (46.4 quadrillion Btu's) of petroleum and 5 additional trillion cubic feet/year (5,375 quadrillion Btu's) of natural gas in 1985. This increase would result in a U.S. domestic oil production of 17 million barrels/day in 1985. Also, development of U.S. shale oil at an assumed cost of $11/barrel could be increased from zero in 1974 to 1 million barrels/day in 1985 with accelerated development. U.S. energy demand has grown about 4.5 percent/year from 1960 to 1970; FEA proposes that growth be slowed to about 2.7 percent/year from 1972 to 1985. Further, by instituting energy conservation measures it proposes that the growth rate be decreased to about 2 percent by 1985. The Dupree-West study suggests that growth in energy demand from 1972 to 1985 would occur at a rate of 3.7 percent.

3-4. *The Potential for Energy Conservation.*—The Department of the Interior projection did not take into account the potential for energy conservation.[11]

Although there has been substantial disagreement as to the effectiveness and potential side effects of individual energy conservation strategies, there seems to be a general consensus that U.S. energy consumption is not inextricably tied to a growth curve that projects the past into the future. A vigorous conservation program could have the effect of slowing national energy demand and thus relieving some of the pressures for rapid development of energy resources throughout the Nation. The Council on Environmental Quality has established a year 2000 energy consumption level of 121 quadrillion Btu's (rather than a projected 191.9 quadrillion Btu's) as a goal.

In the absence of governmental action, a considerable amount of energy conservation can be expected in the future simply because of market pressures—as prices for energy increase the incentive to conserve energy will also increase. The energy market place in the United States, however, contains many disincentives to energy conservation that could be overcome by governmental action. These disincentives include:

a. Energy prices do not reflect total costs of environmental damage, and some cleanup costs are borne by the general public rather than by energy consumers in proportion to their consumption. Thus, energy is underpriced, discouraging some conservation measures that would be realized at prices reflecting energy's total costs.

b. Electricity rate structures favor increased consumption. Thus, large consumers who may have the most opportunity to conserve energy are not encouraged to do so by the existing rate structure.

c. Although there is a wide range of efficiency among energy-using products doing the same job (automobiles, refrigerators, air conditioners, etc.), information about energy costs is often confusingly and ineffectively communicated to the consumer.

d. Energy costs are paid for over a long period of time, whereas the cost of conservation measures often is reflected in the initial purchase price of the energy-using products and are thus more visible and more difficult to pay for because of high interest rates.

e. Many regulations governing energy-using processes and products inhibit conservation efforts; for example, freight rates are higher for scrap and other recycleable materials than for virgin materials.

The Government can attack these disincentives either by (1) affecting the cost of energy through restructuring electricity rates or taxing energy, or (2) providing or requiring provision of information about energy effectiveness of products, (3) granting tax deductions for conservation measures, or (4) by direct regulation of energy consumption through establishing minimum standards for efficiency of appliances, improving home insulation, rationing of gasoline, restricting parking, and other regulatory devices. Although there is considerable debate as to the relative merits of monetary inducement and direct regulation for achieving energy conservation, elements of both appear to be probable features of governmental programs.

Several recent studies have sought to predict the effect on future energy demand that may result from the simultaneous establishment of a whole range of conservation measures. The primary reason for noting these studies is to indicate the appropriate degree of skepticism one should have about the energy consumption estimates provided by "United States Energy Through the Year 2000." Every conservation estimate postulates conservation of more energy than the NGP was postulated to produce, even in the "high" GDP. However, because certain other sources, e.g., imported oil and natural gas, may be unavailable or prohibitively expensive, one should nevertheless refrain from concluding that the potential need for NGP coal will be eliminated by conservation.

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[11] The projections do account, however, for expected savings in energy production and utilization efficiency. In the electrical sector, the heat rate (the heat energy needed to generate a unit of electricity for fossil-fueled powerplants) was assumed to decline from 10,494 Btu/kilowatt hour in 1971 to 9,450 Btu/kilowatt hour in 2000 for a 10 percent gain in efficiency. For nuclear powerplants, the heat rate was assumed to decline from 10,660 Btu/kilowatt hour (represented light water reactor fuel usage) to 9,000 Btu/kilowatt hour (representing a mix of light-water high-temperature gas reactors and liquid metal fast breeder reactors), for an efficiency gain of 15.6 percent. In addition, the energy input per dollar of value added in the industrial sector was assumed to decline from 101 to 76; however, part of this decline is artificial in that it reflects a bookkeeping shift of losses to the electrical sector.

3-5. ***Recent Studies***.–A recent National Academy of Engineering study[11] estimates potential savings from a series of energy conservation measures to be 8 to 9 million barrels/day of oil equivalent, or 17 to 19 quadrillion Btu's/year by 1985. This represents about a 15 percent savings from expected energy levels in that year. The suggested measures include a range of industrial conservation measures yielding a 10 percent savings in industrial energy; increases in space heating efficiency and better building insulation standards; transportation improvements such as carpooling, lower speeds, improved aircraft load factors, smaller automobiles, more public transit systems; and improvements in industrial process efficiency.

The Energy Policy Project of the Ford Foundation has prepared a report on its studies in exploring energy sources.[12] Two "alternate futures" or scenarios are presented: a "Technical Fix," which is calculated to halve the long-term 3.4 percent growth rate in U.S. energy while maintaining our standard of living and avoiding major alterations in lifestyle, and a "Zero Growth Scenario," which would halt per capita energy growth but entail very substantial changes in the U.S. economy, in residential patterns, and other areas.

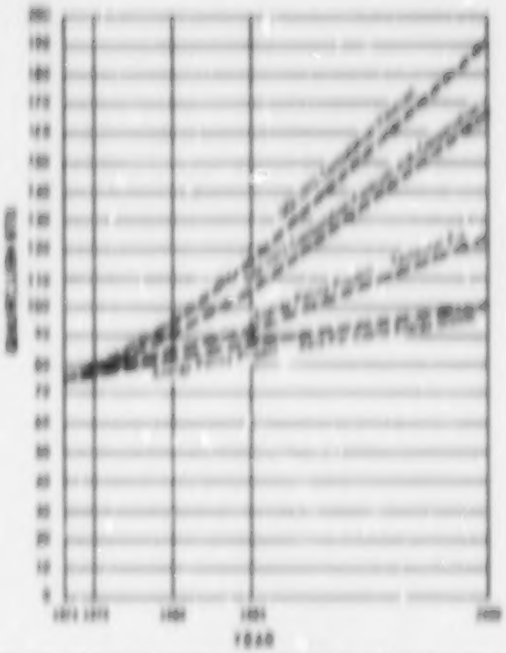

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Figure III-7. Alternative energy demand projections.

While the "Zero Growth Scenario" (fig. III-7) projects the lowest level of energy consumption, the measures necessary to achieve it–a drastic trend away from single family housing; a major shift in the U.S. economy towards agriculture and high-technology, low-energy industry (with consequent large-scale importing of high-energy products such as fertilizer and aluminum), and far greater concentration on service-oriented employment; major shifts in transportation toward fewer trips and far greater use of public transportation and so forth–are extraordinarily difficult to analyze with respect to both their possibility of being implemented and their potential side effects.

The "Technical Fix" represents a 17 percent savings in total energy consumption by 1985 (over the total consumption assuming no major conservation measures) and a 35 percent savings by 2000. The actual conservation measures are quite similar in temper to those discussed in the Academy of Engineering study.[11] The most interesting aspect of the "Technical Fix" is the implications it would have for energy supply. According to the report, the reduction in energy demand implied by the scenario would allow the United States to forego extensive development of some major new energy sources. For instance, the study report says "the nation could choose not to expand coal mining generally, in either the East or the West, because of environmental or social problems, or to restrict surface mining to particular." For instance, a 15 percent energy savings represents a quantity of energy that is approximately twice as great as the entire NGP coal energy contribution to national energy production under the "high" CDP in the year 2000. Such an action, however, would still have to be accompanied by a substantial growth in nuclear energy to prevent energy shortages.

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[11] U.S. Energy Prospects: An Engineering Viewpoint, Task Force on Energy of the National Academy of Engineering, Washington, D.C., 1974.

[12] "Exploring Energy Choices," Ford Foundation, Library of Congress catalog card No. 74-77787, 1974.

[13] Op. cit., p. 20.

A third analysis of potential energy conservation possibilities has been made by the Office of Energy Conservation, then in the Department of the Interior. This analysis considers conservation efforts that involve only increases in the efficiency of energy use but no restrictions on energy use, such as rationing. The conclusion of this analysis is that the Nation has the capacity to reduce year 2000 consumption from 191.9 to 160.8 quadrillion Btu's through increased efficiency in its use of energy (fig. III-8).

There is no consensus that these energy conservation strategies will achieve the energy savings they predict. A growth rate in U.S. energy consumption of only 1.7 percent/year—the goal of the "Technical Fix" conservation scenario—is clearly an ambitious one. Such rate is one-half of the 20-year historical rate—and approximately one-third of the rate of the past half decade. Furthermore, even with such a lower rate of growth our energy supply problems will not have been solved. The report qualifies the "Technical Fix" scenario by saying, "if the pace and mix of economic growth remain unchanged, energy consumption . . . would resume at a higher rate of growth, beyond the year 2000, as new opportunities for cutting out waste become harder to find. Even if the . . . growth rate stays at 1.7 percent per year extended into the next century, a level of 180 quadrillion Btu's (versus 72 in 1972) would be reached by 2025 and 275 quadrillion Btu's per year by 2050."

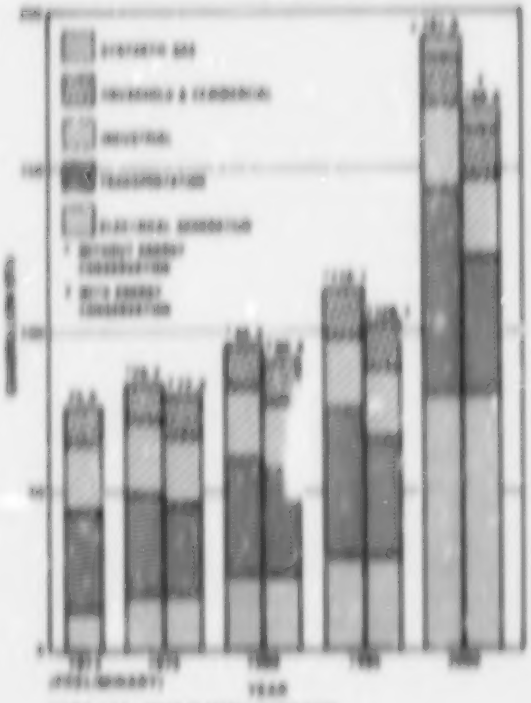

Figure III-8. Energy conservation.

3-6. *Markets for NGP Coal.*—The 1972 Interior consumption forecast is based on the assumption of significant increases in coal production. The study forecasts NGP coal production increasing at more than the proportional amount (table III-5 and fig. III-9). Table III-6 shows the coal production required to meet the alternatives studied by FEA and reported in the Project Independence Final Task Force Report.

The expected markets for NGP coal are:

- Export of coal from the region, allowing its use in electric powerplants in large portions of the United States and particularly the Midwest.
- The production of synthetic natural gas from coal as less expensive sources of gas become unable to meet demands.
- The generation of electric energy at mine-mouth plants and other powerplants in the NGP in an effort to supply energy for use both in the NGP region and export.

The demand for NGP coal energy—in the form of coal, CSNG (coal synthetic natural gas), or electricity from mine-mouth powerplants—is dependent not only on the demand for all energy fuels but also on the competitive position of NGP energy in each of its potential market areas. This competitive position in turn depends upon a number of

Table III-5. –*Coal production–NGP and other*[1]

	Million tons (percent of total coal production by weight)				
	1973	1975	1980	1985	2000
NGP	33 (5.5)	52 (8.2)	107 (14.5)	197 (19.6)	362 (25.5)
Remaining U.S. production	557	584	633	788	1,056

[1] Based on "Intermediate" Coal Development Profile (CDP-II).

Table III-6. –*Future coal production–NGP*[1]

	Millions tons per year			
	1975	1980	1985	1990
Business as usual	49	102	155	188
Accelerated development	65	187	304	387
Remaining U.S. production	–	–	–	–

[1] Project Independence Final Task Report, Coal–November 1974, tables 9 and 11.

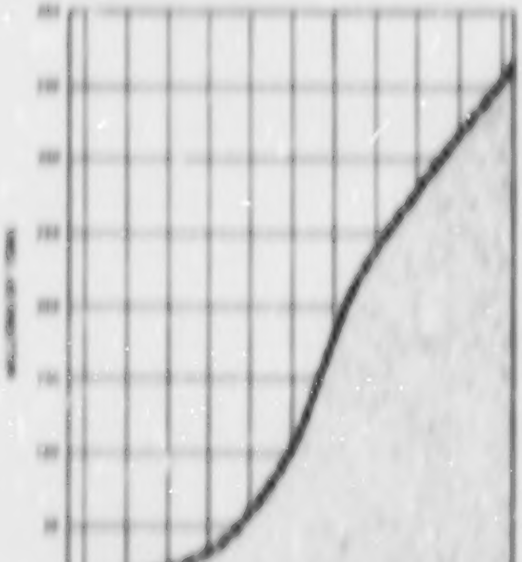

Figure III-9. Forecast of coal production in the Northern Great Plains.

factors that involve the availability, price, and environmental attractiveness of the alternative energy sources.

The predictive analysis must consider all of the following issues:

- Future environmental regulations on exploration and exploitation of the alternative energy resources and the consequent effect on their availability and price.
- Future national policy with respect to reliance on imported fuels and the inverse: foreign willingness to supply fuels to U.S. markets.
- National policy on supporting and financing new energy sources and associated research.
- Future environmental regulation on fuels used (for instance, restrictions on the sulfur content in fuels).
- Pace of development of alternative energy production and pollution control technologies.
- Future policies of utility commissions in market areas. Several of these issues will

have, by themselves, a very powerful affect on the future viability of NGP energy development. At the same time, many of the issues are hard to analyze or predict.

a. *Export Market for NGP Coal.*—The delivered price of NGP coal by unit train in the Midwest exceeds the price of indigenous Midwest coal. Coal produced in mines of the NGP States is at present transported to steam-electric generating plants in the West, North Central, and East North Central States where recently imposed mandatory limits on permissible levels of SO_2 emissions have created demand for low sulfur coals and thus have supported the longer rail hauls and higher transportation costs. In unit-train shipments of coal from Montana and Wyoming to Minnesota and Illinois, 60-75 percent of the estimated 1973 delivered cost is accounted for by transportation. Coal slurry transportation may significantly reduce these transportation costs sufficiently to permit NGP coal to have a lower delivered price in the Midwest on a cents/Btu basis than indigenous coal.

Table III-7 illustrates the premium being paid for NGP coal in four NGP mine/midwestern market combinations. This difference ranges from 1.1 cents/million Btu's in Minnesota to 19.0 cents/million Btu's in Illinois-Indiana. Even greater differences would occur for longer hauls to the East. Column 7 of the table reflects the premium per million Btu's currently being paid in the Midwest for NGP coal delivered by unit trains and an estimated premium that would be paid if a 15-million-ton/year capacity slurry pipeline was the method of delivery. The data imply that a pipeline of this capacity, if justified by the volume of shipments and if the coal slurry cost estimates are reliable, can deliver NGP coal to many midwestern markets at lower costs than indigenous coal thus permitting even high sulfur NGP coal to undersell indigenous coal. If one adds a medium estimate of the cost of emission control to the cost of midwestern coal, but not to the cost of NGP coal, unit-train delivery of NGP coal will be at lower Btu cost than midwestern coal in many midwestern markets. In general, NGP coal's competitiveness depends upon its ability to meet the Federal and State regulations including SIP'S (State Implementation Plans)[12] without stack gas emission controls.

Despite the current economics of shipping NGP coal further than the Midwest, NGP coal has been shipped as far east as West Virginia. In this latter case, the key reason seems to be that most State utility commissions have allowed an automatic passthrough of fuel transportation costs (in other words, these costs can be charged directly to the consumer without the necessity for hearings), thus allowing western coal to successfully "compete" with Appalachian coal that has a lower delivered cost per Btu.

Other factors involved in the shipment of NGP coals outside their traditional market areas include:

- The lack of availability of and/or the reluctance of many utilities to install stack gas desulfurization equipment, which has rendered significant quantities of eastern and midwestern high-sulfur coals (at least temporarily) useless (while some NGP coals have been able to comply with air pollution standards).
- The past Mideast oil embargo, which forced oil-burning powerplants to compete in the coal market and drove spot coal sale prices up to levels which made long-haul coal shipments economically feasible. FEA data, however, indicate few oil-fired plants have converted to coal.

The long-term market for NGP coal depends upon whether this coal can maintain its current advantage over competing midwestern and eastern coals. For example, the automatic passthrough of transportation costs may not be a long-term factor in promoting eastern markets for NGP coal. Some State utility commissions are currently reviewing the effects of permitting automatic fuel cost adjustment price increases.

There are large deposits of low-sulfur coal in the East. A recent study[13] estimated some 17,541 million tons of bituminous coal to be

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[12] SIP's are plans which provide for implementation, maintenance and enforcement of NAAQS in State air quality control regions.

[13] U.S. Bureau of Mines, "The Reserve Base of United States Coals by Sulfur Content, Part 1, The Eastern States"; report is in the review stage for eventual publication as an Information Circular.

Table III-7.–*Price of NGP coal in midwest markets compared to prices of midwest coal*

	(1)	(2)	(3)		(4)		(5)	(6)	(7)		(8)		(9)
Origins, destinations and transport mode	Actual cost of transportation by unit trains, cents/10⁶ Btu		Cost of transportation by slurry[a]		1973 coal cost f.o.b. mine in origin state, cents/10⁶ Btu		Estimated average total cost of western coal delivered to state, cents/10⁶ Btu	November 1973 actual price of midwestern coal purchased by steam-electric plants in state destinations cents/10⁶ Btu	Difference in cents/10⁶ Btu of NGP coal delivered compared to midwestern coal delivered		Cost of stack gas cleaning[b]		Price advantage of NGP coal in cents/10⁶ Btu, delivered compared to midwestern coal delivered with emissions controls
	Range	Average											
Montana to Minnesota (approx. 815 miles)													
Unit train	18.6 to 31.6	24.5		+	16.2	=	40.7	39.6	1.1 more	+	15.7	=	18 less
Slurry			14.6	+	16.2	=	30.8	39.6	8.6 less	+	15.7	=	28 less
Wyoming to Minnesota (approx. 1,100 miles)													
Unit train	30.5 to 32.1	31.3		+	16.2	=	52.8	39.6	13.2 more	+	15.7	=	6.1 less
Slurry			19.8	+	16.2	=	41.3	39.6	1.7 more	+	15.7	=	17.6 less
Montana to Ill.-Ind. (approx. 1,270 miles)													
Unit train	45.4 to 51.7	49.2		+	16.2	=	65.4	46.4	19.0 more	+	15.7	=	0.3 less
Slurry			22.5	+	16.2	=	39.1	46.4	7.3 less	+	15.7	=	26.6 less
Wyoming to Illinois (approx. 1,110 miles)													
Unit train	42.5 to 45.0	43.7		+	21.5	=	65.2	46.4	18.8 more	+	15.7	=	0.5 less
Slurry			20.0	+	21.5	=	41.5	46.4	4.9 less	+	15.7	=	24.2 less

[a] Based on 1.8 cents/million Btu/100 miles [illegible] million ton/year capacity [illegible]. For 3 million ton/year capacity, the cost would be [illegible] cents/million Btu/100 miles. These estimates are modified from the Southwest Energy Study to reflect the Btu value of NGP coal.

[b] Sulfur Oxide Control Technology Assessment Panel–April 1973. Reflects costs of wet lime/limestone/Ca(OH)$_2$ slurry scrubbing. [illegible] mills/kWhr adjusted by heat rate of 10,000 Btu/kWhr. $\frac{1.57 \text{ mills/kWhr}}{10{,}000 \text{ Btu/kWhr}} \times 10^6 = 157 \text{ mills}/10^6 \text{ Btu} = 15.7 \text{ cents}/10^6 \text{ Btu}$

acceptable under new source performance standards for SO_2 emissions. Most of this coal occurs in eastern Kentucky and West Virginia. This tonnage assumes 100 percent conversion of the sulfur in the coal to SO_2 up the stack. Although these are mostly deep underground-minable coals and have considerably greater mining costs than do NGP coals, the high transportation costs of NGP coal may curtail its eastern markets. An important consideration is that much of this low-sulfur coal in the East is of metallurgical quality. Although the concept of burning this specialty coal under boilers to generate steam for power generation is possible, such use would constitute a relatively inferior use of a superior coal and may adversely affect the supplies of metallurgical grade coal.

Another factor that may affect future export markets for NGP coal involves the future price and availability of adequate and reliable stack gas cleaning devices for sulfur oxides. The Environmental Protection Agency maintains[17] that stack gas desulfurization technology is available and sufficiently reliable to warrant installation in fossil-fueled powerplants. The utility industry has in general disagreed with this position and has contended that currently available equipment is too unreliable to be used in a powerplant. Whatever the situation, the future availability and price of reliable desulfurization equipment could affect NGP coal markets.

A further uncertainty in the market for NGP coal lies in the ability of NGP coal to meet low sulfur requirements imposed by the Clean Air Act. NSPS for powerplants under the Act allow for only 1.2 pounds/million Btu's of SO_2 emission from powerplants. It has generally been assumed that 95 percent of the sulfur present in coal is emitted as SO_2 from a powerplant. This figure is based on extensive measurement at powerplants burning bituminous coal.[18] More recently, the U.S. Bureau of Mines has made extensive similar tests on SO_2 emissions from North Dakota lignite powerplants.[19] Some 59 tests showed SO_2 emissions ranging between 40 and 100 percent of the sulfur in the coal. This range of emissions was correlated with the presence of other impurities in the coal, alumina, and silica tending to increase the fraction of sulfur emitted and calcium and sodium oxides tending to decrease it. Pacific Power and Light has reported a test at its Dave Johnston Plant in which 73 percent of the sulfur in subbituminous coal was converted to SO_2.[20] Figure III-10 and table III-8 illustrate the maximum allowable sulfur content of various quality coals based on the NSPS. For comparison purposes, two curves are shown in figure III-10, one for 95 percent conversion of sulfur to SO_2 and one for 70 percent conversion. As an example, coal with a heat content of 8,000 Btu at a conversion rate of 95 percent must have a sulfur content of less than 0.5 of a pound; at a conversion rate of 70 percent this same pound of coal could have approximately 0.7 pound of sulfur/million Btu heat input and meet NSPS standards.

Those coals in the NGP which do not meet permissibility requirements for SO_2 emissions will require further expenditures to meet such standards. A potential means to this end is pretreatment to reduce sulfur content prior to combustion. There are three forms of sulfur in coal: organic, sulfate, and pyritic. Organic sulfur is sulfur combined with the organic substance in coal and is often the predominant form of sulfur in NGP coals. Pretreatment by washing (crushing and flotation) does not remove organic sulfur. Sulfate sulfur is sulfur in the form of calcium or iron sulfates and is a minimal constituent of coal and therefore relatively unimportant. Pyritic sulfur is sulfur disseminated throughout the coal as pyrite or marcasite. Washing will remove some pyritic sulfur from coal by floating the crushed coal away from the heavier pyrite. Removal is successful to varying degrees, depending upon the size and distribution of the pyrite. Pyritic sulfur is usually a higher proportion of total sulfur in the high-sulfur coals of the East than the lower sulfur coals of the NGP and therefore

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[17] "Final Report on Projected Utilization of Stack Gas Cleaning Systems by Steam Electric Plants," SOCTAP (Sulfur Oxide Control Technology Assessment Panel), April 1973.

[18] *Compilation of Air Pollutant Emission Factors*, EPA, 1973.

[19] Gronhovd, G. H., Tufte, P. H., and Selle, S. J., "*Some Studies on Stack Emissions from Lignite Fired Powerplant*," Lignite Symposium, USBM Energy Research Lab, Grand Forks, North Dakota, May 9-10, 1973.

[20] Application to EPA for a permit to construct Unit 4 of the Jim Bridger Plant, under section 110 of the Clean Air Act, Pacific Power and Light Company, 1974.

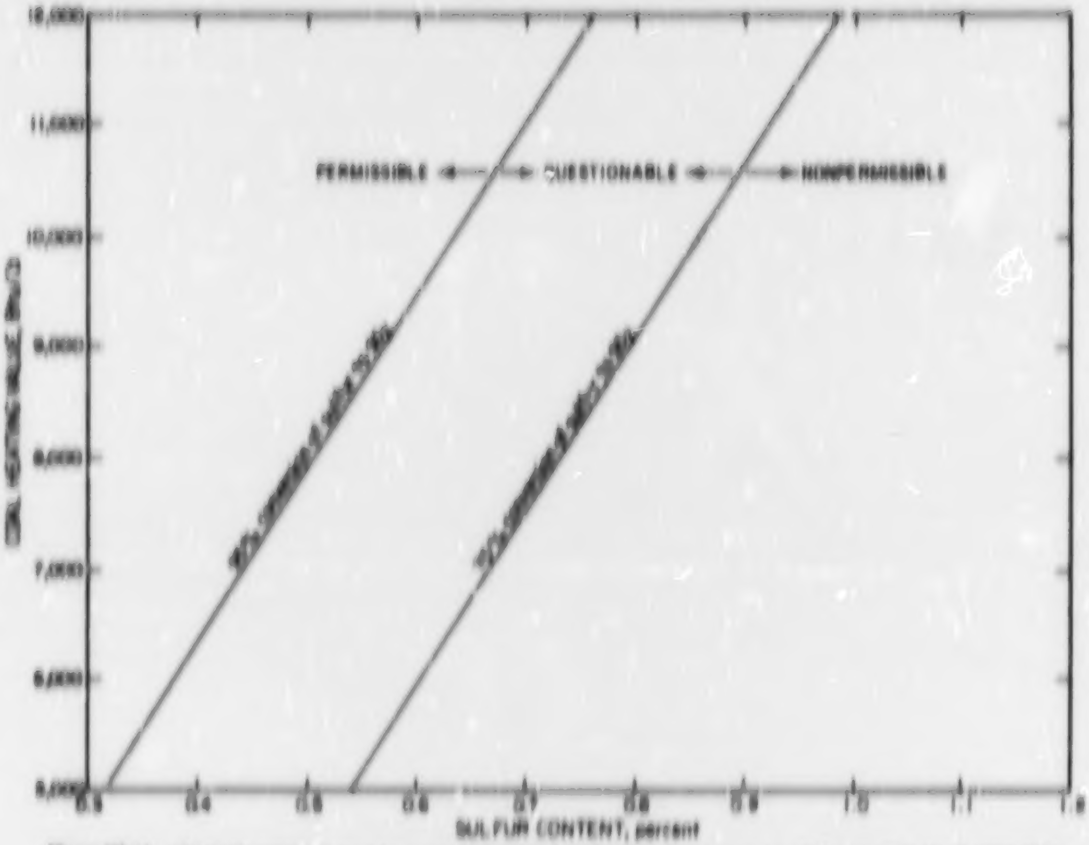

Figure III-16. Allowable sulfur content for coals having different Btu values and assuming different percents of conversion.

Table III-8.—*Btu values and allowable sulfur content*

Btu value per pound	Maximum allowable sulfur content under NSPS, percent*
6,000	0.38
7,500	.47
9,000	.57
10,000	.63
12,500	.79
15,000	.95

*Assuming 95 percent conversion of sulfur to gaseous sulfur oxides.

washing is more applicable to eastern coals.

Blending high- and low-sulfur coals is a possible solution, provided the resulting blend is compatible to boiler design criteria and sufficient low-sulfur coal is available.

One method of assuring clean air from stacks is the installation of FGD (flue gas desulfurization) systems (commonly known as stack gas scrubbers). Such systems can achieve an 85 to 90 percent reduction in SO_2 emissions. The cost of stack gas cleaning shown in column 8 of table III-7 is representative of those costs anticipated for new plants. However, the retrofitting of FGD systems to older plants would cost from 1.5 to 2.5 times this amount.[31]

Valid data are not available on the percentage of NGP coal that would require such treatment for use in powerplants. It should be noted that, because possibly only a very small percentage of SO_2 emissions must necessarily be removed from stack gases emanating from plants burning NGP coal, such controls may not be as expensive as the high-efficiency SO_2 controls required for plants burning higher sulfur coals.

Additionally, requirements of SIP's under the Clean Air Act limit emissions from existing powerplants and, hence, place sulfur limitations on the coal they may burn. These requirements may be more or less stringent than the NSPS; in areas of multiple sources they may be more stringent. All of these requirements (NSPS and SIP's) are, of course, designed to enable the Nation to meet National Ambient Air Quality Standards set to protect public health and welfare.

Unless outright emergency shortages of competitive fuels occur, the delivered cost of NGP coal will play a crucial role in determining its markets. Although the analyses presented previously forecast potentially favorable cost advantages for NGP coal, these advantages were computed on the basis of 1973 prices. These potential price advantages may not be sustainable. The Interagency Coal Task Force for Project Independence has estimated the minimum delivered costs for various coals in several market areas. Figure III-11 compares these costs for 1980. (These costs are based on allowing mine owners a 15 percent rate of return over the 25-year life of the mine.) An analysis of these estimates reveals that NGP deep-mined coals are not competitive in most market areas, usually by a wide margin. The NGP surface-mined coals are roughly competitive with eastern and midwestern deep-mined coal in midwestern markets. Although NGP surface-mined coals are not strictly competitive with midwestern and eastern surface-mined coal on a delivered cost/Btu basis, most of these latter coals are high in sulfur content and will require a greater expense in meeting NSPS's than will that NGP coal which requires desulfurization. That portion of NGP coal not requiring desulfurization has yet a greater competitive edge.

Although figure III-11 assumes explicit values for transportation costs, such values are, in fact, variable. Significant differences exist between different modes of transportation and, indeed, within each mode depending upon the capacity of the mode, its financing arrangements, and its configuration and management. Table III-9 presents cost data for transporting coal in unit trains or through pipelines and compares these to the cost of transporting coal energy, as electricity, through high-voltage transmission lines. The data show that high-capacity slurry pipelines (where coal is mixed with water to form a suspension called "slurry," which is then shipped via pipeline) offer some potential for reducing transport costs, but the accuracy of the data for this mode is not as certain as the others due to less experience with operating slurry pipelines.

The costs of electric power transmission shown in table III-9 are subject to certain qualifications. The heading "Cents/million Btu of primary energy/100 miles" means the cost of delivering 1 million Btu's of coal to a point 100 miles distant. When expressing this cost for electricity, which is secondary energy, the reference is to the cost of delivering the amount of electricity that can be generated from 1 million Btu's of coal. The costs are comparable because the coal, once delivered, will be burned to produce an equal amount of electricity. The expenses of power losses

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[31] "U.S. EPA National Public Hearings on Power Plant Compliance with Sulfur Oxide Air Pollution Regulations," Report of the Hearing Panel, U.S. EPA, Washington, D.C., January 1974, 137 pp.

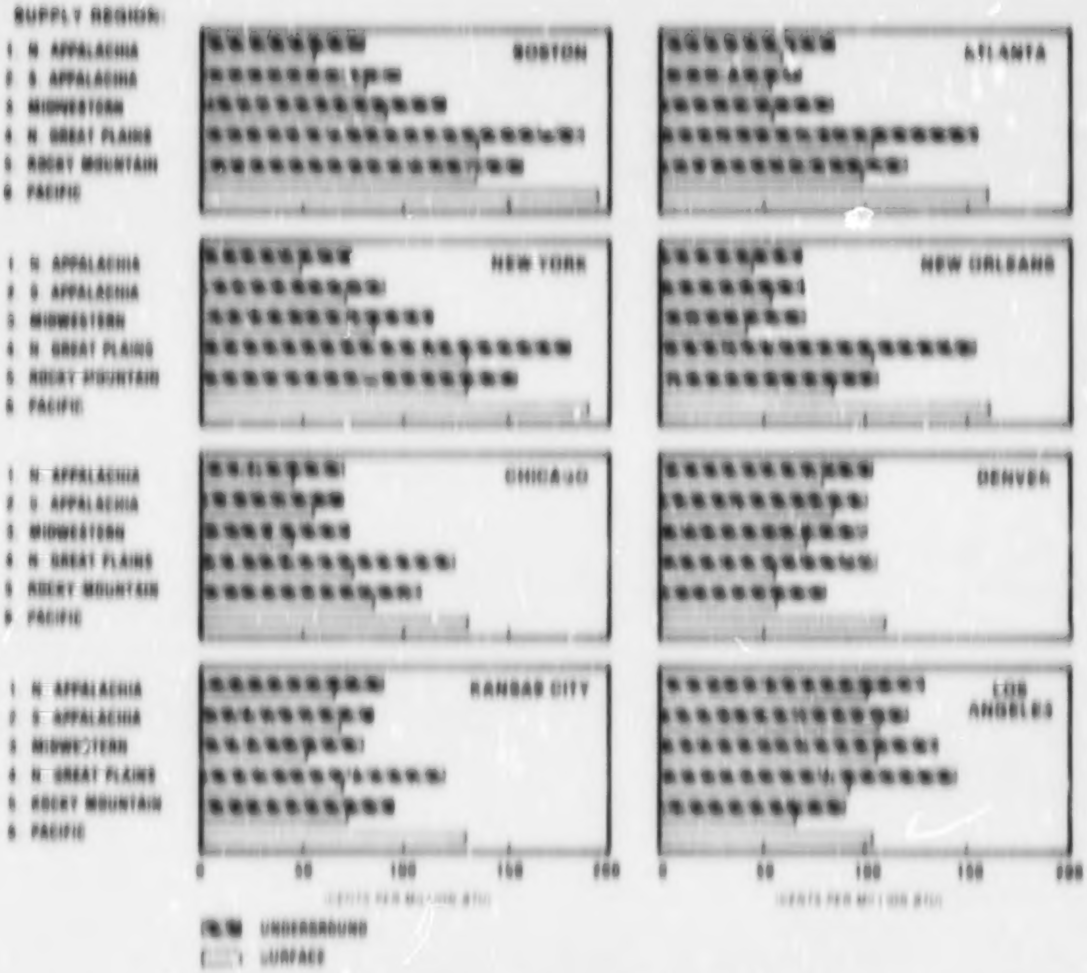

Figure III-11. Estimated average minimum delivered cost of coals in cents per million Btu—1980[a] by unit train. Does not include desulfurization costs, where required.

associated with power transmission and the energy needed to move coal by unit train or slurry pipeline are included in the costs of transportation shown in table III-9.

Different transmission line designs have complex balances between capital costs and transmission losses. Generally, higher capital costs are associated with lower transmission losses. When a 700-kV a.c. powerline is more than 1,000 miles in length, a capacity of about 2,000 megawatts and losses of about 5.5 to 6 percent can be expected. A 500-kV a.c. line would carry 1,000 megawatts and lose about 7 to 10.5 percent. A d.c. line might be applicable only for long distances and high wattages such as a plus or minus 600-kV line carrying 4,000 to 5,000 megawatts. Losses of 8.4 to 10.4 percent can be expected for such lines. These powerlines are generally designed to lose about 5 to 10 percent over a 1,000-mile distance because of the tradeoffs between capital costs and transmission losses.

The erection of structures beneath an EHV transmission line is inadvisable, but with precautions the land can be cultivated or grazed if the EHV line meets the standards of the Bonneville Power Administration. Most lines are designed to meet these standards.

Table III-9. —*Transportation costs of energy*

Form of energy transport	Cents/million Btu of primary energy/100 miles	
	Range for all references	Likely range for Western States
Slurry pipeline	1.0-5.0[*] 1.3-3.8[†]	1.0-5.0
Unit train	2.5[†] 3.2-600-mile length[‡] 3.9-1,089-mile length[‡] 2.7-4.0[§]	2.5-4.0
Electricity	2.8-6.4[†] 3.0-3.6, 700 kV a.c.[*] 3.6-4.8, 500 kV a.c.[*] 4.8-6.6, 345 kV a.c.[*] 6.6-9.0, 200 kV a.c.[*]	2.8-9.0

[*] The 1970 National Power Survey, Part III, Federal Power Commission, 1971.

[†] The Southwest Energy Study.

[‡] Unit Train and Volume all-rail Tariffs on Coal Shipments from Montana and Wyoming Mines, Branch of Interfuels and Special Studies, Sept., 1973.

[§] Burlington Northern, Inc., Tariffs, September, 1973.

During the 12 to 18 months prior to November 1974, the competitive position of NGP coal changed. All transportation modes increased in price about 10 percent according to industry reports. The delivered cost of NGP coal increased in lesser amounts than competing coals. Long-term contracts for NGP coal were being negotiated at $5 or more per ton (f.o.b. mine) at the end of the period.

b. ***Market for NGP Synthetic Natural Gas.***—A number of energy companies have shown substantial interest in developing facilities for the production of CSNG in the NGP states and elsewhere and have invested in research programs and plant development planning. Some companies who have announced Lurgi-type gasification projects in the NGP include:

- —Panhandle Eastern Pipe Line Company and Peabody Coal Company (one plant in eastern Wyoming)
- —Natural Gas Pipeline Company of America (one plant in Dunn County, North Dakota)
- —Northern Natural Gas Company and Cities Service Gas Company (four plants in the Powder River Basin)
- —Michigan Wisconsin Pipeline Company (several plants in North Dakota)

These plants, however, are only in the planning stage. Although massive pipeline construction could expand the market area for NGP CSNG, the most probable markets will be those that can be supplied by existing pipelines. These markets are in North and South Dakota, Nebraska, Minnesota, Iowa, Montana, Wyoming, Colorado, Utah, California, Nevada, Arizona, Washington, Oregon, and Idaho.

Implicit in the acceptance of CSNG as a viable product is a belief that over the long term:

- —Either the price of gas at the wellhead will continue to be regulated and maintained at a level which will ensure shortages of natural gas (which woul require supplements from other hig priced, nonregulated sources) or

- The price of gas will be deregulated and rise to (and remain at) such a level that provision of supplemental supplies (such as CSNG) would be come profitable.

Without an outright shortage of gas or a substantial price increase for natural gas, CSNG could not possibly be economically competitive in the interstate market. To illustrate:

> Prices of high Btu CSNG from western coal ranged from an estimated $2.50 to $3.00 MSCF (thousand standard cubic feet) based on 1974 prices.[32]
>
> Federal Power Commission Price Ceiling on Interstate Natural Gas Sales—$0.52 MSCF.
>
> Intrastate long-term sales (unregulated) $0.90 to $1.20 MSCF.

At present, a partial deregulation—or at least a series of allowable price increases—is taking place, and general price increases are expected to continue. Most authorities expect these increases to stimulate exploration for new domestic sources of natural gas but not to compensate for predicted shortfalls in supply. For instance, the National Petroleum Council[33] predicts that U.S. gas demand will increase from 22 trillion cubic feet per year in 1970 to more than 41 trillion cubic feet per year in 1985, while maximum domestic production will be 30.6 trillion cubic feet[34] per year (under extremely favorable circumstances). This very substantial gap would have to be made up by supplementary supplies, including (potentially) NGP synthetic gas (if the shortages occur in areas that can be reasonably served by NGP gas).

Although NGP-produced synthetic gas could conveniently serve the four markets listed in table III-10, each of these potential CSNG markets can be served by several competitive fuels which could conceivably threaten the NGP market share. Table III-10 shows the competitive supplementary (i.e., not including domestic natural gas, the *primary* fuel) gaseous fuels available to each of the market areas and their estimated prices. An examination of the table shows that Alaskan/Canadian gas, if available at indicated prices (Canada may raise prices considerably above this level), and Nuclear Stimulated Natural Gas (assuming the technology proves feasible) could be very price competitive with NGP CSNG in its potential market areas and could well inhibit the development of NGP CSNG. Thus, estimates of CSNG production in the NGP are subject to considerable uncertainty. However, the Arctic gas (Alaskan and MacKenzie Delta gas) pipeline is projected to cross the NGP on its way east. If sufficient demand exists to justify both the Arctic gas pipeline and significant CSNG production in the NGP, this section of the Arctic gas pipeline (called the Northern Border Pipeline) could facilitate delivery of NGP CSNG to midwestern and eastern markets. Although NGP synthetic gas will probably cost less to produce than synthetic gas from eastern coal, estimated transportation costs may be expected to limit NGP markets to the four areas shown in table III-10.

c. *Generation and Export of Electric Power.*—A third market for NGP coal is electric power generation in the NGP. In 1971, 33.8 percent of NGP coal production by tonnage was consumed in the region and 12.7 percent was exported in the form of electricity.

Power generation utilities in the region have made plans for expanding their capacity through the early 1980's; however, recently planned expansions have been curtailed. As the surplus generating capacity within the NGP and the transmission capacity determines the ability of the utilities to export power, the supply potential of export power from the NGP is essentially fixed through about 1985. The Department of the Interior has forecast further increases in electric generation between 1982 and 2000, but utilities have generally not announced specific plant sitings beyond the early 1980's.

NGP coal is currently competitive in some export markets even though transportation charges are substantial. It follows that NGP

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[32] FPC application by El Paso Natural Gas Company (Docket No. CP73-131) and Trans-Western Gasification Company (Docket No. CP73-[illegible]).

[33] Op. cit., p. 19.

[34] This is a much more optimistic forecast of domestic production of both NG and SNG than that made by the 1973 Interior forecast.

Table III-10.—*Competitive supplementary gaseous fuels*
(Source: Branch of Natural Gas, Division of Fossil Fuels, USBM)

Market area	Fuel	Wholesale price $/million Btu (1972 dollars)
North and South Dakota, Nebraska, Minnesota, Iowa	CSNG* (Western)	1.10–1.27
	CSNG (Eastern)	1.24–1.40
	LNG†	1.35
	NSG‡	0.86–1.05
	North Slope** (into U.S. West)	1.37
	North Slope (into U.S. Central)	1.16
	Alberta Gas	0.97
Montana, Wyoming, Colorado, Utah	CSNG (Western)	0.91–1.08
	CSNG (Eastern)	1.34–1.50
	NSG	0.67–0.86
	North Slope (into U.S. West)	1.07
	Alberta Gas	0.67
California, Nevada, Arizona	CSNG (Western)	1.04–1.21
	CSNG (Eastern)	1.52–1.68
	LNG	1.47
	NSG	0.80–0.99
	North Slope (into U.S. West)	0.90
	Alberta Gas	0.50
	Alaska LNG	1.25
Washington, Oregon, Idaho	CSNG (Western)	0.96–1.13
	CSNG (Eastern)	1.26–1.42
	LSNG§	1.40
	LSNG	1.47
	NSG	0.73–0.92
	North Slope (into U.S. West)	0.87
	Alberta Gas	0.47
	Alaska LNG	1.22

*Coal Synthetic Natural Gas.
† Liquified Natural Gas.
‡ Nuclear Stimulated Natural Gas.
**Gas from Alaskan North Slope and Canadian Mackenzie Delta.
§ Liquid Synthetic Natural Gas.

coal is in an excellent competitive position within the region. Table III-11 and figure III-12 illustrate in-region utilities plans for future generating capacity through 1990. All facilities shown on figure III-12 were included as sites in the CDP's. For South Dakota, which is close to active in-region coal mines, and the coal-producing States of Montana, Wyoming, and North Dakota, almost all additions to total generating capacity will depend on

Table III-11.—*NGP five-state region—Projected additions of electric generating capacity, 1972-1990*[1]

Plant name and company		Ref. No. for Fig. III-12	Capacity megawatts (MW)	Fuel type	Scheduled operation date
NORTH DAKOTA:					
Leland Olds 2	(BEPC)	1	438	Lignite	10/75
Center 2	(MPCoop)	2	435	Lignite	5/77
Lignite 1	(CPA)		400	Lignite	11/78
Underwood 1	(UPA)	3	500	Lignite	11/78
Underwood 2	(UPA)	4	500	Lignite	11/79
Lignite 2	(CPA)		400	Lignite	11/79
Proposed	(BEPC)	5	500	Lignite	5/79
Proposed	(MDU)		20	Oil, gas	5/80
Proposed	(MDU)	8	100	Lignite	5/81
Proposed	(NSP)	6	800	Lignite	5/81
Proposed	(OTPC)	7	200	Lignite	5/81
SOUTH DAKOTA:					
Big Stone	(OTPC)		430	Lignite	5/75
Yankton 4	(NWPS)		6	Oil	1/74
Aberdeen	[illegible]		20	Oil, gas	5/78
Mitchell	(NW[illegible]		20	Oil, gas	5/79
Proposed	(NWPS)		20	Oil, gas	5/80
Proposed	(NWPS)		100	Coal	5/81
MONTANA:					
Colstrip 1	(MPC)	9	330	Coal	7/75
Colstrip 2	(MPC)	9	330	Coal	7/76
Colstrip 3	(MPC)	9	700	Coal	7/78
Colstrip 4	(MPC)	9	700	Coal	7/79
Libby 1	(Army)		121	Hydro	7/75
Libby 2	(Army)		121	Hydro	10/75
Libby 3	(Army)		121	Hydro	1/76
Libby 4	(Army)		121	Hydro	4/76
Libby 5	(Army)		121	Hydro	10/82
WYOMING:					
Dave Johnston	(PPL)	10	750	Coal	1972
Jim Bridger 1	(IPC)		500	Coal	6/74
Jim Bridger 2	(PPL)		500	Coal	9/75
Jim Bridger 3	(PPL)		500	Coal	9/76
Wyodak	(PPL)	11	330	Coal	5/77
Naughton	(UPL)		860	Coal	3/79
Wheatland 1	(MBC)		500	Coal	81
Wheatland 2	(MBC)		500	Coal	82
Wheatland 3	(MBC)		500	Coal	83

Table III-11.—*NGP five-state region—Projected additions of electric generating capacity, 1973-1990*[1]—Continued

Plant name and company		Ref. No. for Fig. III-12	Capacity megawatts (MW)	Fuel type	Scheduled operation date
NEBRASKA:					
Hebron 1	(NPPD)		50	Gas	1973
McCook 1	(NPPD)		48	Gas	1973
Sheldon 3	(NPPD)		50	Gas	1973
Jones St. 1, 2	(OPPD)		116	Gas	1973
Cooper 1	(NPPD)		778	Nuclear	1973
Ft. Calhoun 1	(OPPD)		457	Nuclear	1973
Fremont	(FDU)		80	Gas, coal	1976
Gentleman 1	(NPPD)		650	Coal	1977
Gentleman 2	(NPPD)		600	Coal	1980
Proposed	(OPPD)		100	Gas, oil	1978
Proposed	(OPPD)		200	Gas	1979
Proposed	(NPPD)		200	Gas	1980
Ft. Calhoun 2	(OPPD)		900	Nuclear	1980
Lynch	(NPPD)		1,600	Hydro	1983
Cooper 2	(NPPD)		1,100	Nuclear	1984
Ft. Calhoun 3	(OPPD)		1,100	Nuclear	1990
Otoe County	(OPPD)		600	Coal	1979

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[1] Data from Federal Power Commission on 10-year future programed units as furnished by utility regional reliability councils.

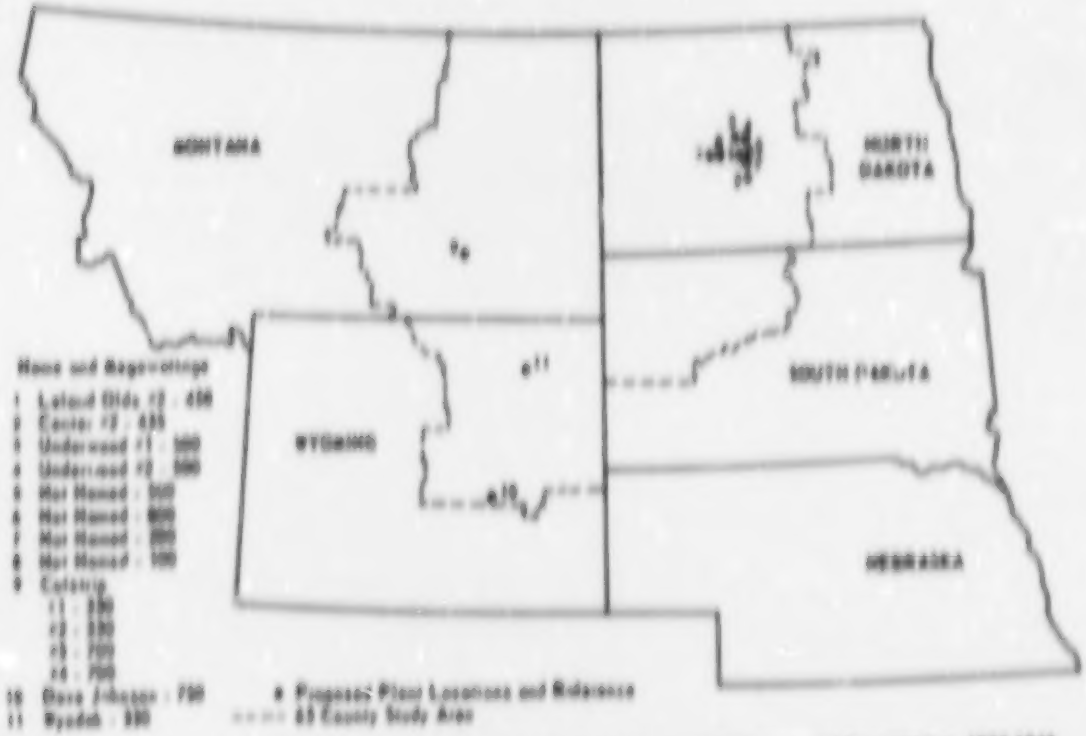
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
WYOMING
NEBRASKA
Name and Megawattage
1 Leland Olds #2 : 438
2 Center #2 : 435
3 Underwood #1 : 500
4 Underwood #2 : 500
5 Not Named : 500
6 Not Named : 800
7 Not Named : 300
8 Not Named : 100
9 Colstrip
#1 : 330
#2 : 330
#3 : 700
#4 : 700
10 Dave Johnson : 750
11 Wyodak : 330
● Proposed Plant Locations and Reference
- - - - 63 County Study Area

Figure III-12. Location in 63-county study area of new coal-fired electric powerplants projected for operation, 1973-1985.

subbituminous coal or lignite. Nebraska, which is farther from the coal mining area, will depend on nuclear power for most additions to capacity but will, nevertheless, add approximately 1,850 megawatts of coal-burning capacity.

d. *Market Conclusions.*—In conclusion, the time frame becomes important when discussing the market for NGP coal energy. For the immediate future, there is a very clear and broad market for NGP coal. Coal in general—and low-sulfur coal in particular—is in short supply. Spot sales of bituminous steam coal have reached $40 per ton. High-sulfur coal, while available, cannot be widely used because most powerplants do not have stack gas desulfurization equipment and will not have it for several years. Thus, the high transportation costs of NGP coal may be somewhat irrelevant in many markets, especially with the price of oil so high.

The long-term market for NGP coal energy is less certain. There are several factors that are distinctly favorable to optimistic market predictions. Chief among these are expectations that, without massive new development, coal demand will outstrip supply as U.S. energy demand continues to grow while alternative energy sources cannot keep up. The NGP coal would then find a large market merely because it is an available and reliable energy source. Also, although stack gas desulfurization equipment should be readily available in a few years, a continuation of the capital shortage in the electric utility industry will probably discourage installation of this expensive equipment. Instead powerplants would tend to use low-sulfur fuels—such as NGP coal—to meet emission requirements.

However, circumstances could be substantially different than pictured above. Although several energy companies have announced coal gasification plants for the NGP, these plans may change if Canadian and Arctic gas can be produced at lower cost and is available to compete in potential NGP markets. Given an availability of capital—perhaps provided by the Federal Government—and sufficient eastern and midwestern production, the utility industry will have the clear option of installing stack gas desulfurization equipment and burning high-sulfur coals. Although the availability of slurry pipelines and high desulfurization costs for competing coals would be in its favor, NGP coal may still be at a serious price disadvantage in some key markets if the Interagency Coal Task Force's predictions are correct. Thus, truly massive coal development in the NGP—on a scale consistent with the high Coal Development Profile (CDP-III)—will occur only if the factors controlling the markets for NGP coal develop in a way distinctly favorable to such development. This is by no means a certainty.

3-7. *Federal and State Actions That Might Affect Development.*—Federal and State actions may have a substantial effect on NGP coal development:

a. *State Policies.*—States will play a major role in determining the rate and extent of coal development in the NGP. The amount of State taxes imposed on coal development facilities and on the product will influence its price and competitive position in the marketplace. State plant siting acts and the allocation of water resources and State air pollution control regulations will also influence the level and type of coal development. Montana and North Dakota have acted to discourage the construction of coal conversion plants on future leases of Federal lands.

b. *Mineral Leasing Policy.*—The Federal and State governments control vast reserves of coal in the NGP area. The expansion or increased coal leasing or the imposition of diligent development requirements on existing coal leases could affect current coal production as well as future production.

c. *Import Policies.*—Coal is the prime energy candidate, through conversion, to make up for shortfalls of imported energy supplies such as natural gas and petroleum. By a policy of expanding or contracting import quotas, the Federal Government will affect the domestic demand for coal.

d. *Environmental Quality Standards.*—Any relaxation of air quality standards will cause a shift away from use of NGP coal in some markets to eastern or midwestern coal to meet electrical generating requirements.

c. Research and Development Support.—Future coal demand may be related to the availability, size, and use of research and development funds. For instance, if Federally-funded nuclear and solar energy programs result in technological advances, demand for coal will be reduced. If, however, funds are provided for development of coal gasification and liquefaction techniques and these techniques are developed, demand for coal will increase providing the conversion cost is competitive.

3-8. Method Used to Assess Range of Potential Changes.—The 1973 Department of the Interior consumption forecast[11] contains the data used to develop the three CDP's for the NGP, i.e., CDP's I, II, and III. The CDP II (intermediate CDP) is the rate of coal production that is consistent with the national energy consumption and production forecast.[12] CDP II represents an estimate of the NGP coal production rate for the purposes of export, in-region power generation, electrical export, and SNG (synthetic natural gas) production as viewed in the Interior forecast. Explicitly assumed is that sulfur dioxide emission control devices will be available for installation in 1980.

Clearly, other rates of production are possible. Therefore, the two additional CDP's were postulated: a lower rate of coal production (CDP I) sufficient to meet existing contractual agreements and increases in regional demand for coal and a higher rate of coal production (CDP III) based on the maximum contribution that NGP coal might reasonably be expected to make in alleviating shortages in the supply of imported oil and gas and domestic nuclear electric generation.

Rates of production and types of consumption of coal will, of course, be vitally affected by conservation measures (sec. 3-4) and by land use policies. Some of the alternatives are discussed in this section within the framework of the three CDP's.

a. Rationale for Use.—Each CDP postulates an amount of coal that could be produced and why; where mines, power generation, and SNG facilities could be sited; how much acreage would then be disturbed and where; how much water would be required; and how many jobs would be created. Each CDP characterizes the developmental situation in sufficient detail for broad analysis of impacts and issues.

In each CDP, the coal produced is used in a number of ways. These include electric generation for in-region consumption, electric generation for export, coal export, and SNG production. A quantification of these uses is summarized graphically in figure III-13. Some of the projected effects of development are shown in table III-12 to permit comparison among the three CDP's.

The low rate (CDP I) represents the minimum reasonable rate of coal production since it includes only those increases in production which were already guaranteed (that is, secured by signed long-term contracts) or highly probable (that is, supplying announced regional thermal-electric powerplants) as of 1973.

The higher rate (CDP III) is based upon the following specific assumed shortfalls below the projected levels of national energy supplies: imported petroleum—3 million barrels/day in 1985, 5 million barrels/day in 2000; Canadian natural gas—1,000 billion cubic feet/year in 1980, 2,100 billion cubic feet/year in 1985, and 4,000 billion cubic feet/year in 2000; nuclear generating capacity 30,000 megawatts in 1985 and 240,000 megawatts in 2000. The coal production estimates for this CDP are based upon significant exports to the largest conceivable market area that NGP coal might serve in order to make up a portion of the shortfall. Because of increasing energy demand and the uncertainties of imported energy, it is prudent to consider the possibility that the maximum rate of production of NGP coal may be necessary. CDP III probably represents maximum production because of likely shortages of transportation facilities, capital, and skilled manpower in the region and the high cost of shipping coal long distances.

This method of analysis, that is, the concept of three coal development profiles, was chosen since it provides a means for establishing realistic minimum and maximum rates of possible coal production, as well as a middle rate, and relating the resultant production levels to both the national energy situation and

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[11] Op. cit.: [illegible]

[12] Op. cit.: [illegible]

Table III-12.—Coal development profile data

(all numbers cumulative)

	1970	1971	1975	1980	1985	2000	2020
New employment (thousands)	0	—	—				
CDP I	0	—	—	17	6	18	
CDP II	0	—	—	23	57	65	
CDP III	0	—	—	88	96	175	
Population increases (thousands)							
CDP I	0	—	—	36	26	82	
CDP II	0	—	—	65	140	245	
CDP III	0	—	—	190	236	516	
Coal mined (MST/yr)							
CDP I	21.3	—	52	91	109	*146	
CDP II	21.3	—	52	107	192	*362	
CDP III	21.3	—	52	160	302	*677	
Number of facilities							
CDP I							
Export mines	—	12	—	14	15	16	
Powerplants (MW in parentheses)	—	0	—	12(5,613 MW)	14(7,613 MW)	20(13,100 MW)	
SNG plants	—	0	—	0	0	0	
CDP II							
Export mines	—	10	—	16	20	24	
Powerplant (MW in parentheses)	—	0	—	12(5,613 MW)	14(6,613 MW)	25(19,400 MW)	
SNG plants	—	0	—	*0	*7	16	
CDP III							
Export mines	—	10	—	16	26	64	
Powerplant (MW in parentheses)	—	0	—	12(5,613 MW)	14(6,613 MW)	25(19,400 MW)	
SNG plants	—	0	—	7	13	41	
Water used (conversion only—thousands of acre feet)							
CDP I							
High use estimate	—	—	—	90	119	243	
Medium use estimate	—	—	—	62	73	153	
Low use estimate	—	—	—	28	32	66	

Table III-12.—Coal development profile data—Continued
(all numbers cumulative)

	1970	1971	1975	1980	1985	2000	2020
Water need (conversion only—thousands of acre feet)—Continued							
CDP II							
High use estimate	—	—	—	98	329	843	
Medium use estimate	—	—	—	62	142	381	
Low use estimate	—	—	—	28	75	139	
CDP III							
High use estimate	—	—	—	300	719	1,595	
Medium use estimate	—	—	—	129	283	618	
Low use estimate	—	—	—	70	153	343	
Land disturbance (thousands of acres)							
CDP I	—	—	—	8	19	103	292
CDP II	—	—	—	8	31	210	671
CDP III	—	—	—	20	72	397	1,473

[1] Includes supply to 6,700 megawatts of coal-fired electric plants outside of 62-county study area but within the five States and coal exported to other States.

[2] Present industry trends indicate no operating gasification plants by 1980.

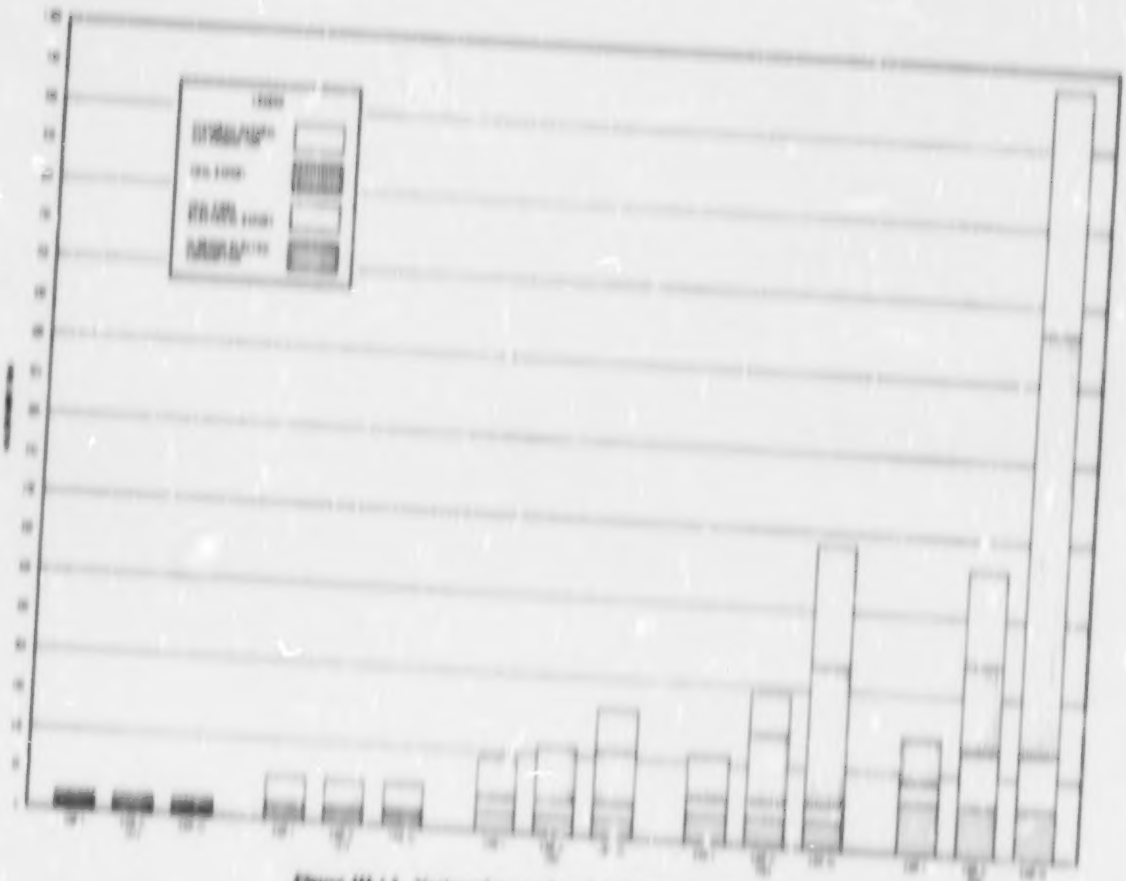

Figure III-11. Various forms of coal use for each CDP.

the impact on the region. This permits a preliminary comprehensive identification and analysis of impact. It does not establish a plan or alternative plans for coal production for the area.

b. *Siting of Mines and Plants*—The projection of mine sites for various CDP's was based upon coal demand, identified by States in the NGP, as estimated by the National Energy Considerations Work Group. The Minerals Work Group first identified the geographical locations of the so-called "strippable" coal reserves in the study area. It was assumed that the optimum (or "unit") sizes of powerplants ranged from 1,025 to 1,250 megawatts and required from 3.5 to 6.8 million tons of coal per year (dependent upon the power produced and the Btu content of the coal which ranged, in the estimates, from 6,000 to 9,650 Btu/lb).[57] Fourteen powerplants were already planned by utilities for completion by 1985. The plants vary from 100 to 800 megawatts. It was assumed that the optimum size for a coal gasification facility was 250 million cubic feet/day which required from 7.1 to 11.5 million tons of coal per year (based again on a range of 6,000 to 9,650 Btu/lb).[58] It was assumed that export mines would produce about 10 million tons/year; however, a few mines from 4 to 9 million tons/year production were sited. It was further assumed that the life of a coal natural gas conversion plant would be 30 to 35 years (powerplants, 35 years). Thus, a total coal requirement for a mine was derived.

Based, then, on the location of mines, the indicated interest of mining companies and "conversion" companies in other sites, the general quality (Btu content) and thickness of the coal, and a cursory evaluation of coal/land ownership, mines and associated mine-mouth plants were sited. First priority was given to those sites for which feasibility studies or actual construction plans had been announced. Proximity of water sources and gas pipelines were not directly considered as a constraint although proximity to drainage channels was considered. Allowances were not made for improved conversion efficiencies. Export mines were sited with some consideration of transportation routes but no consideration of specific destinations for the exported coal. In all siting projections, no special consideration was given to minimizing potential adverse social and environmental impacts.

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[57] Assumes 65×10^{12} Btu per year from coal per 1,000 megawatts of electrical capacity.

[58] Assumes 131.6×10^{12} Btu input per year from coal per 250 million cubic feet/day gas output.

For purposes of projecting energy requirements, it was assumed that liquefaction would not become commercially viable in the NGP within the time frame of the study. Although some liquefaction was acknowledged in the national projections, it was felt that the priority for conversion of subbituminous coal and lignite in the NGP would be for gasification.

Though some low-heat value gas could be used for onsite power generation in a SNG plant, low-heat value gas production was not expected to become an economically viable industry in the NGP due to the abundance of coal suitable for direct combustion. Therefore, no projections for a low-heat value gas-producing industry were made. Recent corporate announcements, however, indicate significant potential use for low Btu gas as a feedstock for the production of nitrogen fertilizer.

c. *Importance of NGP Coal by CDP*.–Table III-13 gives NGP coal production, by CDP, and by both tonnage and as a percentage of national energy consumption.

Table III-13 reflects an increasing percentage contribution by NGP coal to national energy supply in the intermediate and high CDP's but a decreasing contribution after 1980 in the low CDP.[11] The CDP's are based on national energy consumption of 191.9 quadrillion Btu's in 2000. The CEQ (Council on Environmental Quality) has established 121 quadrillion Btu's as an expected demand goal for year 2000 energy consumption. The 14.7 quadrillion Btu's which NGP coal would contribute in 2000 in the high CDP represents about one-fifth of the energy saved under the CEQ goal. If that goal is achieved, some reduction in NGP coal production is likely.

Table III-14 gives State production detail reflecting some concentration of activity in Wyoming and Montana.

d. *Current Outlook in Relation to the CDP's*.–The CDP coal extraction rates were

Table III-13.–*NGP coal production*

CDP	1971	1975	1980	1985	2000
			Million short tons		
Low (I)	21.3	52	91	108	134
Intermediate (II)	21.3	52	107	192	362
High (III)	21.3	52	160	382	977
		Percent of national energy consumption supplied by NGP coal			
Low (I)	0.46	0.97	1.42	1.39	1.13
Intermediate (II)	0.46	0.97	1.67	2.47	2.83
High (III)	0.46	0.97	2.50	4.91	7.64

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[11] For the year 2000, in the intermediate CDP, national coal consumption would be 14.4 percent of total energy consumption. In the low CDP, national coal consumption would be 14 to 14.4 percent of total energy consumption. In the high CDP, national coal consumption would be over 21.3 percent of total energy consumption, the exact amount depending upon the response of non-NGP coal to assumed shortages.

Table III-14.–*Coal production from each NGP State for each CDP*

	(Million short tons)				
	1971	1975	1980	1985	2000
Montana					
Low (CDP I)	7.1	20	34	39	58
Intermediate (CDP II)	7.1	20	41	75	133
High (CDP III)	7.1	20	64	153	393
Wyoming					
Low (CDP I)	8.1	23	37	43	55
Intermediate (CDP II)	8.1	23	47	73	110
High (CDP III)	8.1	23	54	153	386
North Dakota					
Low (CDP I)	6.1	9	19	26	33
Intermediate (CDP II)	6.1	9	19	44	119
High (CDP III)	6.1	9	42	76	198

projected in early 1973 by the Energy Work Group. Actual production plans by industry were then changing substantially and have continued to change. To determine the latest industry projections, Montana, North Dakota, and Wyoming updated their data for a 1980 target date as shown below:

NGP Estimated Production in 1980 (million tons)	
CDP I	90
CDP II	107
Expected production	151
CDP III	160

The States' expectation of coal production for export, power generation, and SNG is based on contracts and the best estimates of individual companies. It includes one 10 million tons/year mine for one CSNG plant in North Dakota that is expected to be in operation by 1980.

The 151 million tons/year 1980 estimate is 5 percent below the CDP III estimate and 41 percent above the CDP II estimate. The CDP II was projected by the Energy Work Group in early 1973 to be the most probable production level. The 151 million tons/year current industry expectation is greater than anticipated and indicates an increasing interest in developing NGP coal. The production that actually takes place, however, could change significantly from either the CDP estimates or industry expectations.

PART IV—LAND, WATER, AND AIR RESOURCES OF THE NORTHERN GREAT PLAINS

A. Introduction

4-1. *General.*—Most of the portion of the NGP area encompassed by this study is characterized by broad horizons of open, rolling terrain. Topographic features only a few hundred feet above the plains are impressive. In Dunn County, North Dakota, for example, two large hills rising 600 feet above the plains are referred to as mountains. The NGP stretch nearly 350 miles north to south—from Canada on the north to central South Dakota on the south—and almost 450 miles east and west from central North Dakota to central Montana (plate 9).

In the rolling grass and brush-covered plains of the eastern part of the region, a lone tree is an outstanding feature. A low butte or a hazy mountain range in the distance is an attraction. It is a country of wind. Wind that quickly dries soils and drifts snow during the blizzardy winters. It is a dry country; only 2 percent is covered by the waters of lakes and streams. Annual precipitation ranges from 10 to 26 inches. Much of plains region only receives 12 to 16 inches of precipitation in a year. Thornwaite[48] said in 1941 that out of 37 years, 1 had been humid, 1 moist subhumid, 5 dry subhumid, 25 semiarid, and 5 arid. The arid and some of the semiarid years are probably too dry to permit revegetation of disturbed land without irrigation.

The NGP is a land of big cattle and wheat ranches. Ward County, North Dakota, has the smallest average size farm, 815 acres. Natrona County, Wyoming, has the largest, 11,105 acres. In most areas farms and ranches must be large because many acres are needed to produce enough to support a family. Seventy percent of the area is pasture and range; 26 percent is cultivated for wheat, barley, flax, rye, oats, corn, alfalfa, and sugar beets, but "wheat and meat" are the main agricultural products. In 1971, a little less than one-twelfth of all U.S. wheat was produced in the region. Less than 3 percent of the land is irrigated.

There are few people, only 4.4 per square mile, compared with Iowa and Ohio having 52 and 263 persons per square mile, respectively. Many have a deep love for the land. A frontier ethic of "stand on your own two feet" is strong. There are Indians: the Sioux, the Northern Cheyenne, Crow, Assiniboine, Gros Ventre. The six major reservations include 5.6 million acres or 6.4 percent of the land. About 25,000 individuals live on the reservations resulting in a density of 2.9 persons per square mile.

Even though there are relatively few people in urban areas of the NGP, such areas are expanding significantly. Between 1958 and 1967, the built-up urban areas increased 37 percent to 1.2 million acres.

The transportation network is the only development spread across the whole NGP. There are 5,440 miles of major electric transmission lines, 88,563 miles of rural and municipal roads, 5,000 miles of railroad lines, 7,421 miles of oil and gas pipelines, and 100 public airports.

a. *Resources of National Importance.*—Before the coming of the white man, the NGP were inhabited by a mobile and powerful Indian people. The first white men to exploit the region were fur trappers and traders; soon after came the pioneers traveling the Oregon, Bozeman, and other pioneer trails. From the South came the cowboys herding thousands of head of longhorns. There were times of triumph and defeat for both Indian and non-Indian alike. There was the time of Sitting Bull and Crazy Horse and the Battle of the Little Bighorn. Open-range ranching started and then faltered in the terrible winter of 1886-87 and began again. As the cattle industry grew and the miners came to dig for gold, the Indians' hold on the land was weakened and the culture and lifestyle of the non-Indian was established in the NGP.

The rivers of the region are its lifelines. Along them ranches are built, crops are grown, and roads and railways laid down. Rivers are vital to the diverse and abundant fish and wildlife and give variety in the scenery. Segments of Clark's Fork of the Yellowstone, the Yellowstone, the Missouri, and the Little Missouri are being considered for national wild, scenic, or recreation river status. The Upper Yellowstone and Sand Creek in Crook County, Wyoming, are two of this country's few remaining blue-ribbon trout streams.

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[48] Thornwaite, C. W., "Climate and Man," 1941 USDA Yearbook.

Some 2.5 million acres of the 92 million acres that comprise the NGP study area are inventoried as "wild lands";[41] some have potential for inclusion in the National Wilderness System. Most are already federally owned. They are varied in topography and vegetation. Five areas are being considered for inclusion in the Wilderness System. They include portions of the Bighorn Mountains, Theodore Roosevelt National Memorial Park, Little Missouri National Grassland, Charles M. Russell National Wildlife Range, and Lost Wood and Medicine Lake National Wildlife Refuges. Nearly 3 million acres adjacent to the NGP study area in the Missouri Basin may soon be proposed by Congress as "Wilderness Areas."

The rare black-footed ferret, a predator of the more numerous prairie dog, is an endangered species which inhabits the NGP year round. Another well-known endangered species, the very rare whooping crane, and the declining American peregrine falcon migrate through the NGP in spring and fall. Several species inhabit the NGP whose population status is little understood but which may be threatened with extinction. These include the northern swift fox, the spotted bat, the American osprey, the prairie falcon, the prairie pigeon hawk, the northern greater prairie chicken, the mountain plover, the northern long-billed curlew, and the western burrowing owl. The tule white-fronted goose also migrates through the NGP.

The big game of the NGP are another resource of national significance. Before 1800, there were an estimated 700,000 antelope in South Dakota as well as millions of buffalo. Lewis and Clark first met the grizzly here and alerted the rest of the world to his existence. They called him *Ursus horribilis*, the horrible bear. Mule deer, white-tailed deer, and antelope abound in the NGP; and bighorn sheep, Rocky Mountain goats, moose, and elk are still found in the more inaccessible mountainous areas.

Hunting is a part of the NGP culture, with many nonresidents participating in the activity. In 1970, there were more than 90,000 nonresident hunting licenses issued in Montana and Wyoming.

The quality of antelope hunting is outstanding. Hunters also come for deer and elk, sheep, sage grouse, and other upland birds and waterfowl. The high quality of hunting found in the NGP is directly related to the relatively low pressure of hunting on game populations and the millions of acres of relatively unaltered land surface that provides suitable habitat. Examples of habitat quality are shown in figures IV-1 and IV-2.

Other kinds of recreationists visit the NGP as they move to areas on its fringes, such as Yellowstone National Park or the Black Hills. The Badlands in Theodore Roosevelt National Memorial Park, for example, attract large numbers of visitors to its unique scenic features.

All these resources are important to many more people than just those of the region. They are national resources, and many are the last vestiges of what this country once was in its untouched natural state.

b. *Resources of Regional Importance.*—All of the resources of the NGP are important to the people who live there. The unique resources of the region are the fount of both their livelihood and lifestyle. The complex mixture of history, attitudes, and landscape are heritages of great value to the peoples of the NGP.

The resources critical to the rancher are the hay meadows, the surface water for their irrigation, the ground water supplies used for stock watering and the grazing lands. In North Dakota, dryland hay production areas are also important. To the farmer, irrigation water and cropland areas are of critical importance.

The livelihood of a significant number of residents is derived from or associated with production of nonrenewable resources such as

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[41] See page 61 for a definition and discussion of "wild lands."

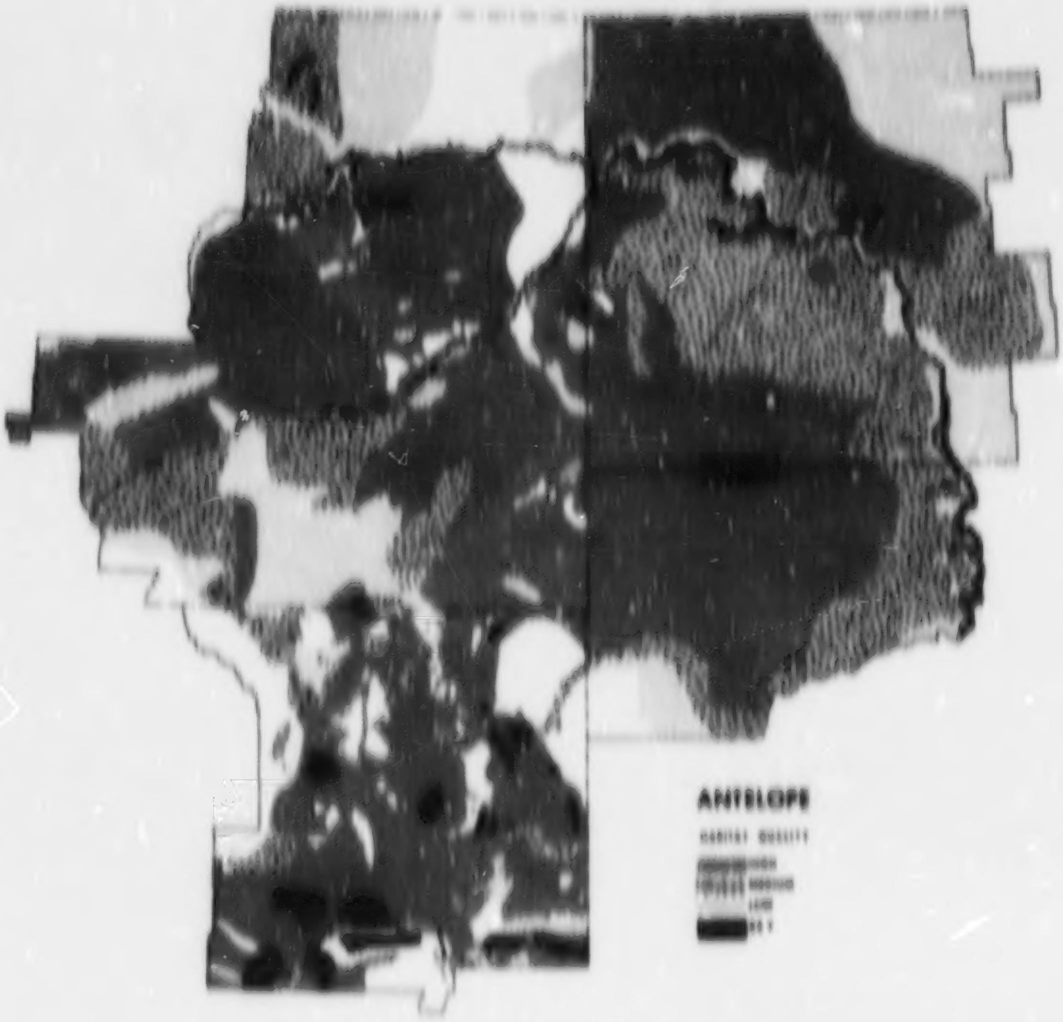

Figure IV-1. Relative quality of antelope habitat in the NGP study region.

coal, gas, oil, and uranium. Without these resources and their production these peoples' livelihood is lost.

Recreation-tourism is a basic industry of the NGP. It provides an outlet for both resident and nonresident. Of prime importance to the industry are the relatively unaltered rivers and plains, the mountains, and the wildlife that abounds therein. The relatively undisturbed open landscape, clear and free-flowing rivers, and the clean air are very important in both a national and regional sense. The impacts of coal development on the land, water, and air of the NGP are subjects of part IV.

B. Land Resources

4-2. *General.*—The most obvious impacts on land resources will come from surface mining; however, there are many other related activities that will also impact land. Some of the derivative issues arise from the questions:

—How will coal development affect the ecosystems in the NGP?

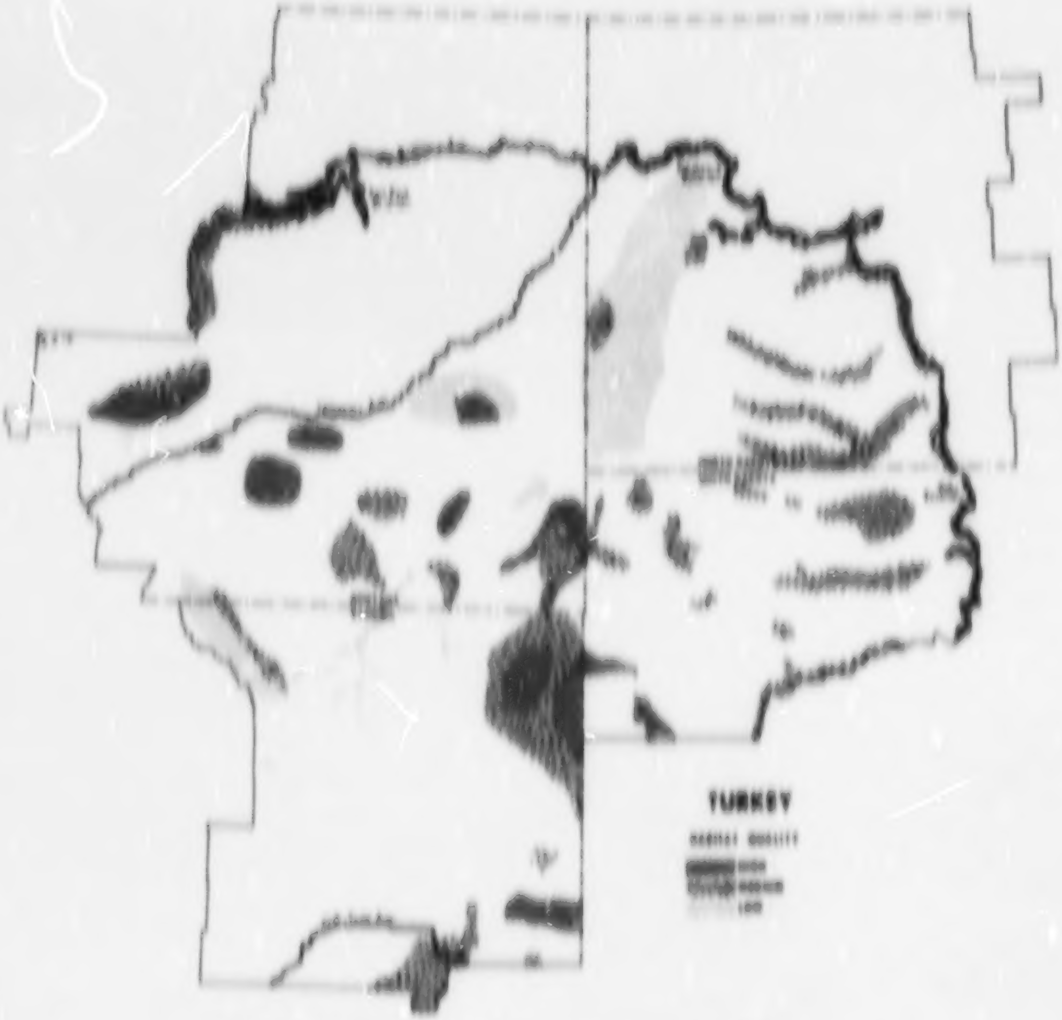

Figure IV-5. Relative quality of turkey habitat in the NGP study region.

- How much land will coal development disturb?
- Can the land be restored after mining is completed?
- What are the long-term as well as the short-term losses?

a. *Ecosystems of the NGP.*—There are six broad ecosystem categories in the NGP area. These are tabulated as follows to provide a perspective for discussion of the area's land resources:

(1) *Grasslands.*—Sixty-seven percent of the NGP is grassland which is underlaid by 59.3 percent of the strippable coal acreage. Precipitation ranges from 18 inches in central North Dakota to 10 to 14 inches in southeastern Montana and northeastern Wyoming.

In the wetter North Dakota area, unplowed native grass is dense and ranges from knee high to waist high. In the drier areas of southeastern Montana and northeastern Wyoming, it is a little more

Ecosystem category[1]	Total acres in category (1,000 acres)	Percent of NGP study area	Surface minable acres in category	Percent of surface minable (acres)
Grasslands	61,646.8	67.3	1,515,725	58.3
Flood plains	3,755.6	4.1	54,597	2.1
Badlands	3,022.8	3.3	31,198	1.2
Brushlands	15,572.0	17.0	725,363	27.9
Ponderosa pine	3,664.0	4.0	272,986	10.5
Mountains	3,938.8	4.3	0	0
Totals	91,600.0	100.0	2,599,869	99.99

[1] Sixteen ecosystems were used in the more detailed work group analyses as shown on plate 7. They were condensed into these six categories to simplify discussion. Grasslands include: short grass, midshort grass, midgrass, grassland sandsage, midtall grass, foothills grassland, and prairie oak savanna. Brushlands include: grassland-sagebrush and sagebrush-steppe. Mountains include: Black Hills pine, Douglas-fir forest, pine-Douglas fir, and subalpine. No ecosystems are combined in badlands and ponderosa pine. Flood plains are termed stream bottoms in text to incorporate closely associated adjoining landscape rather than just the flood plains; however, percentages shown on plate 7 refer only to the acreages in the flood plain.

than ankle deep and is mostly blue grama grass, western wheat, and needle and thread grasses. Much of the knee-high grasslands of northeastern Montana and northwestern North Dakota have been plowed and converted into farms. In the short-grass areas of southeast Montana and northeast Wyoming, only about 10 percent of the land is farmed. Throughout the grasslands, if the land is not farmed, it is grazed by livestock and some wildlife.

Throughout the grassland there are also forbs (herbs) that mix the bright colors of their blossoms with the various shades of green. There are some shrubs, more as one goes from wetter to drier areas. There is big sagebrush for which the West is famous. Wildlife include antelope, mule deer, jackrabbits, prairie dogs, black-footed ferrets, meadowlarks, sharp-tailed grouse, and birds of prey. Around cropland are ring-necked pheasant and red fox. The land and pothole country of northwestern North Dakota and northeastern Montana is part of the North American "duck factory." The endangered whooping crane passes through here annually.

Most of the grassland is rolling open country and because they are so rare and seen for such great distances, every hill must have a name—from Smokey Finger to Horse Nose Buttes.

Wildlife is the most important recreational resource of the grasslands. The big game, birds, and fish attract hunters, fishermen, and wildlife observers from all over the United States as well as serving as recreation (and a food source) for people of the NGP.

The grasslands are also the site of many historic attractions ranging from Custer's Battlefield to hundreds of areas where archeological remnants of Indian life are found.

Revegetation of most disturbed grasslands will be easier than other areas since topography is gentle and soils are fairly well developed. Rehabilitation of disturbed grasslands is especially important since so much mining might take place in the grasslands.

(2) *Flood plains.*—About 4 percent of the study area is in flood plains which is underlaid by 2.1 percent of the strippable coal acreage.

The rivers, flood plains, and adjoining landscapes are "the rivers of life" for the region. Historically, and at present, most human activity radiates outward from the flood plains. Places like Billings, Bismarck, Sheridan, Rapid City, Casper, and Douglas are in or adjoining the flood plains. Flood plains, being few in number in the NGP, are vitally important. They are the principal landform that are in attractive contrast to the adjoining open rolling country, giving it a unique character and identity in their passage through the grasslands, badlands, brushlands, and timberlands.

Typical flood-plain vegetation includes cottonwood, willow, green ash, box elder, chokecherry, greasewood, salt grass, and western wheatgrass. They are the home of fur-bearing animals and other wildlife such as mule deer, white-tailed deer, red fox, and numerous species of birds. Flood plains are ecologically delicate areas, extremely susceptible to disruption. The present stable streambanks and most of the adjoining flood-plain landscape would be nearly impossible to reconstruct. Mining in the stream bottoms could disrupt the entire ecosystem for many miles downstream. The loss of vegetation from stream bottoms would make the adjacent uplands less valuable for wildlife as well as domestic stock. Wildlife ranging over many miles often depend on the narrow thread of flood plains. Revegetation of the bottoms, under correct procedures, would be made easier because of the shallow ground water. Disturbance of the stream channels would, however, adversely affect the natural flood-retarding character of the flood plain.

The flood-plain ecosystem is a complicated and dynamic environment. The aquatic and terrestrial life comprise an ecosystem that is unequaled in its complexity elsewhere in the region. The purely aquatic environment and the riparian habitat are inextricably joined in their interdependence. The plants and animals that live in the streams depend on a continuing supply of nutrients that are washed from the adjacent land. Consequently, their habitat may be severely degraded by runoff of excessive nutrients or sediment. Many insects and other invertebrates that spend their adult phases on land, and are a food source for the small mammals and birds living on the flood plain, spend their juvenile phases in the stream where they are a food base for fish which in turn are preyed upon by other animals. Shrubs and trees stabilize banks and provide refuge for small fish. In their turn, the flora require the water for their growth and reproduction. Bacterial activity in the streams purifies the water, benefiting the many animals that rely upon it. Because of the many chemical and biological processes associated with a stream ecosystem, it is tolerant of a wide variation of conditions. If one system, however, becomes inoperable it can have cascading impacts that destroy parts of, and in some cases, the entire natural community.

Coal-related development may change streams by increasing the TDS (total dissolved solids), BOD (biochemical oxygen demand), and temperature. Significant deviations from the normal range of any one of these factors could have deleterious effects on aquatic animals. The effect of excessive change must be recognized as affecting the total spectrum of biochemical and physical conditions existing at the time and not on one factor alone. For instance, as temperature rises, the metabolic rate of coldblooded animals increases and their biological oxygen demand increases. Further, as temperature rises, the amount of oxygen that is naturally in the water decreases so that at the very time more oxygen is required, less is available. This then exposes the animal to two stresses, one directly attributable to increased temperature, the other indirectly to reduced oxygen. As this simplified example illustrates, the biochemical and physical changes that may occur must be fully analyzed and evaluated before impacts can be integrated. Such integration is beyond the scope of this study, but when conducted it must necessarily be related to specific sites because of their individual nature and complex variation.

The streams in the NGP at their headwaters are characterized by their steep gradient, low water temperatures, TDS and sediment loads, and high oxygen concentrations. The headwaters are trout water. They are clear; they support insect larvae with high oxygen demands. As the streams enter the plains, they begin changing. Their gradient decreases and they flow more slowly and eventually meander creating large flood plains. The TDS and sediment loads as well as nutrient levels increase, summer temperatures are higher, and dissolved oxygen content is reduced, sometimes to critical levels.

The aquatic species begin to change. The gravel beds become caked with sediment. Trout are unable to spawn here. The insect larvae that live here are those that tolerate lower dissolved oxygen concentrations and higher temperatures. Channel catfish and cyprinids are among the dominant species in such areas.

If coal development results in increased water temperatures, TDS, BOD, and sediment loads, a diminution in the quality of trout habitat and a net loss in trout production can be expected. Species now living in the lower portions of the streams will invade and occupy the areas vacated by the trout.

(3) *Badlands.*—The badlands are raw, bare, rapidly eroding, usually south-facing slopes of exposed layers of shale, lignite, and sandstone. In the study area, 3.3 percent is referred to as badlands and is underlaid by 1.2 percent of the strippable coal acreage.

The badlands are mostly along the river courses: the lower Powder River where it joins the Yellowstone, the south slopes along the upper Tongue, and in a belt 5 to 25 miles wide and more than 200 miles long along the Little Missouri in North Dakota. There are large badland areas along the Missouri in the Charles M. Russell National Wildlife Range.

In the gentler rolling parts of the badlands and in pockets along deep, steep-sided coulees, a shallow soil supports plant growth, grazing, and there are even some small areas of dryland farms. Precipitation of only 10 to 14 inches annually makes a harsh environment even less hospitable.

Typical vegetation includes shadscale, greasewood, and salt grass on the thin soils. On better soils big sagebrush, fringed sagebrush, rabbit brush, bluebunch wheatgrasses, and Rocky Mountain junipers are common.

Wildlife includes mule deer, elk, prairie rattlesnakes, lizards, rabbits, and a myriad of other prairie animals. Wild turkeys have been reintroduced and are doing well in some locales. The badlands, like the flood plains, are critically important to wildlife, vegetation, and recreation.

Because of the crazy-quilt mixture of raw slopes and strips, patches and flats of shallow soil, and the mixtures of reds, whites, yellows, and grays from clays, bentonites, and brick red scoria, the badlands are extremely fragile. Where altered, they cannot be restored to anything near their original condition. To grow plants would probably require importing cover soil and even then so little is known about the revegetation problems that the results are unpredictable. In any case, the stark, rare beauty of intricately woven steep-sided ridges and coulees could not be duplicated and disturbance would greatly increase erosion. The badlands are likely to be an increasingly important recreation resource as interest in wilderness hiking, camping, and nature study increases.

(4) *Brushlands.*—Approximately 17 percent of the study area is brushland and is underlaid by 27.9 percent of the strippable coal acreage.

Part of the southernmost portion of the study area in Montana and most of northeastern Wyoming is brushland. This area receives some 10 to 14 inches of precipitation per year. The soils are generally lighter with more silty and loamy textures than in the grasslands. The grasses are much the same species as in the grasslands, except for the absence of some of the taller ones. Bluebunch wheatgrass is a major grass species. Salt grass, shadscale, and greasewood indicate local saline soils. Big sagebrush is a dominant woody species. It is an absolute necessity for sage grouse and antelope which are the most abundant game species in this ecosystem and are characteristic of the Northern Plains. Both attract many hunters. The sage grouse is the second largest upland game bird following the wild turkey. Mule deer and antelope winter ranges are located in the brushland along the foothills.

Less than 5 percent of the brushlands is in cropland and less than half the cropland is irrigated. Most of the brushlands are grazed by domestic livestock. During much of the year the land looks dry and desolate. Because so much of the brushland is of low relief, powerlines and plants would be visible for long distances. Much of the surface soil over coal is saline or alkaline and needs special handling. Techniques for properly handling the soil remain to be developed.

Many native plants would be useful in revegetation of strip-mined land. Because of the usually dry climate and frequency of drought, revegetation will take more effort here than in much of the grassland.

(5) *Ponderosa pine.*—Four percent of the study area is forested by ponderosa pine; 10.5 percent of the surface minable coal acreage underlies the forests.

The ponderosa pine forest is the most common and driest of the forests of the NGP. Scattered throughout eastern Montana, northeastern Wyoming, and the western Dakotas, it receives about 12 to 17 inches of precipitation annually. Ponderosa stands usually occur on the more moist north slopes of steep topography, crests of hills, ridges, and rimrock.

Most of the previously mentioned grass species are found in the understory. In addition, western snowberry and skunkbush sumac occur here in quantity. It also is an important wildlife area. Mule and white-tailed deer are at home as well as many species of birds, including Merriam's wild turkey. The pine forest environment is much more complicated than that of the brushlands or grasslands because the trees provide more diverse habitats. A large share of the shallow ground water is recharged from aquifers surfacing in the ponderosa pine ecotype.

(6) *Mountains.*—About 4 percent of the study area is mountainous.

These areas include the wetter pine forest of the Black Hills, Douglas fir, and the subalpine areas of the higher mountains. These receive more precipitation than any area of the NGP, some 18 to 26 inches. The Black Hills and the Big Horn Mountains provide the principal backdrops for the NGP region. Although they do not contain coal, the mountain areas are vitally important to the region and national recreation scene. Coal development activity in the other areas of the region would affect the mountain areas as a result of human in-migration, more powerplants, rights-of-way, air pollution, and possibly water diversion structures.

b. *Rehabilitation Potential of the NGP Surface Minable Land.*—Reclamation possibilities in the NGP will depend on conditions that exist at the restoration site. Factors to be considered are precipitation, soils topography, complexity of the preexisting vegetation, and projected use of the lands. Central to all rehabilitation efforts is the reintroduction of vegetation to the disturbed land. Important factors controlling the potential for revegetating various land types include: (1) amount and distribution of precipitation, (2) soil productivity and stability, and (3) suitability and availability of seeds and plants for revegetation purposes. An examination of these three factors shows that the surface minable lands of the NGP occur in 7 precipitation zones, 17 soil associations, and 9 broad vegetative types.

Of all possible combinations of these factors, 66 occur in the NGP; thus, the surface minable lands can be divided into 66 different kinds of land each with its own revegetation-potential characteristics. Most combinations are found in more than one location. There are a total of 146 areas which have been designated as RRU (rehabilitation-response units) (plate 8). It has been assumed that, regardless of location, RRU that have the same soil-vegetation-precipitation identifications should have similar responses to rehabilitation efforts. These RRU were delineated on a regional basis but in many instances do not reflect site specific data.

Revegetation and other rehabilitation research has been initiated on 15 surface coal mines and 3 large bentonite mines in the NGP. These mines are found on only 14 of the 86 different RRU. Fortunately they are distributed over a sufficiently varied range of RRU to allow some interpolation of results. Both native and introduced grasses, legumes, shrubs, and trees have been established by either seeding or transplanting. Shrubs and trees have been transplanted at seven coal mines with survival and vigor ranging from acceptable to excellent. A detailed examination of these sites plus an analysis of the rehabilitation potential of each of the 86 RRU is included in the Surface Resources Work Group Report. Plate 3 graphically presents these units and divides them into a set of poor, fair, or good potential for rehabilitation.

This study reveals that Mercer and Oliver Counties in North Dakota have a much higher potential for successful rehabilitation than do those in other sample counties (sample counties shown on plate 9). Soils are more productive, vegetation types more suitable, and precipitation higher than in the other sample areas. Rosebud County, Montana, has the next best potential, followed by Bighorn County, Montana, and Campbell County, Wyoming. The poorest rehabilitation potential recorded for Campbell County results from a combination of poor soils, vegetation types that have the fewest suitable and available species, and existence of the lowest precipitation in the NGP coal province.

Although general conclusions such as those drawn above are helpful in comparing differences between areas within the NGP region, it must be noted that relatively little long-term experimentation and research have been directed to the problem of rehabilitating lands being mined for coal in the NGP. Perhaps the most important single point emerging from this study is that the potential for rehabilitating surface-mined land in the NGP is extremely site specific. The general rehabilitation potential can be judged on the basis of climatic, soil and vegetation components, but each site will also have its particular microclimate in terms of specific physiographic, biotic, and hydrologic components. These macrosite and microsite components, as well as the measures employed to effect revegetation, inherently impose constraints on and limitations to successful rehabilitation of surface-mined land in the NGP. Highly sodic or other adverse soil or overburden conditions increase the difficulty of revegetation and may under some circumstances preclude successful revegetation.

Although plate 3 rates lands for their rehabilitation potential, it should be understood that the reference is to potentials for reestablishing vegetation and not to the potentials for rehabilitating topography and shallow aquifers to predisturbance characteristics. The topographic changes resulting from mining thick coalbeds with shallow overburden, such as those described in the Environmental Impact Statement on "Development of Coal Resources in the Eastern Powder River Coal Basin of Wyoming," may significantly alter the surface drainage and erosional patterns of the region. Further studies of such potential effects and the development of appropriate mitigating measures are needed. Areas such as the badlands, flood plains and adjoining breaks, and much of the ponderosa ecosystems may have topographic and geologic characteristics that preclude restoration to predisturbance conditions. Also, the ratings are relative to each other only. Very little if any land in the NGP has been revegetated for sufficient time or with a sufficient variety of species to determine potential success in establishing a permanent ecosystem that will sustain grazing or higher uses. Sites having the highest rehabilitation potentials occur in response units characterized by productive and stable soils, suitable and available plant species, and adequate amounts of precipitation. In general, these high-potential sites are in west-central North Dakota. Surface minable sites that have intermediate rehabilitation potentials are predominantly in southeastern Montana and extreme western North Dakota. Sites having the poorest potentials for rehabilitation occur in northeastern Wyoming and northeastern Montana where RRU are characterized by poorly productive soils, native species that grow slowly, and are difficult to obtain for rehabilitation purposes and low amounts of precipitation.

Estimates of direct onsite rehabilitation costs from two sources range from approximately $700 to $1,800 per acre, depending upon the locations and the problems encountered. The rehabilitation costs shown in table IV-1 include those of land shaping, seedbed preparation, seeding, fertilizing, soil amendments, water control on slopes, mulching, sediment control in detention basins, shrub or tree planting, topsoil replacement, and in some instances irrigation facilities. The largest expenses are usually those of shaping the land and replacing topsoil. Considering the relatively great tonnages of coal that will be mined per acre in the NGP, the cost of revegetation can be accomplished without adding more than a few cents per ton (table IV-1).

These estimates do not include the cost of water. If revegetation is to be attempted during drought periods, irrigation will be required and may significantly increase the rehabilitation expense. In a drought year or period of years when only 4 inches of average precipitation were received, 8 inches of irrigation water would need to be added to assure the minimum of 12 inches for establishing grass species. Using the CEP water cost estimates, it would cost $38 to $325 per acre-foot and would add $25 to $218 per acre to the revegetation expense. If water had to be applied 2 years in succession, it would add $50 to $436, respectively. If 12 inches were required to assure the minimum of 16 inches needed for establishing large shrub and tree species, the per acre cost for irrigation would be increased by $38 to $325 per acre and for watering 2 years by $76 to $650 per acre. If sufficient water of the required quality were available from the mine pit or adjacent ground-water sources this cost might be reduced significantly. Costs for water would be in addition to the $700 to $1,800 per acre rehabilitation costs referred to above. Although irrigation may be needed only occasionally, the expense of the water system may have to be incurred to ensure sufficient water when needed. One alternative to irrigation would be to reseed in the following year on the anticipation that ample rainfall would provide the necessary moisture for growth.

Table IV-1.—*Onsite rehabilitation costs*[1]

Coal seam thickness, (feet)	At a minimum cost of $700/acre cost per ton (cents)	At a maximum cost of $1,800/acre cost per ton (cents)
10	4.94	12.71
30	1.65	4.24
100	0.49	1.27

[1] Assumes 1,416 tons of coal per acre-foot and a minimal 80 percent recovery of coal.

To better understand the problems associated with revegetating these disturbed lands and to determine the potential of restoring them to optimum biological productivity, research in several areas is needed. Some of these areas are:

(1) Analysis and evaluation of chemical and physical characteristics of the existing soils of geologic overburden materials in relation to their suitability for revegetation purposes.

(2) Development of methods and techniques for creating favorable microbiological activity in surface-mine spoils.

(3) Evaluation of the physical and chemical quality of surface and subsurface runoff water from mine spoils under different rehabilitation treatments.

(4) Testing and evaluation of the comparative effects of different organic amendments in the revegetation of surface-mine spoils.

(5) Testing and evaluation of comparative effects of selected inorganic fertilizers in the revegetation of surface-mine spoils.

(6) Development of mechanical-chemical-vegetation techniques for rehabilitating steep, abandoned surface-mine spoils.

(7) Evaluation of the effectiveness of dryland farming techniques known to be effective on various kinds of mine spoils.

(8) Testing and evaluating spoil segregations to eliminate toxic situations and appraising the merits of various surface configurations to enhance water control, moisture retention, and microenvironment.

(9) Development of mechanical criteria for construction of mine dumps to prevent mass slumping and to reduce surface erosion.

(10) Response of revegetative lands to grazing pressure.

(11) Plant materials development and improvement:

(a) Determination of the physiological tolerances of selected plant ecotypes to various soil-water potential stresses and atmospheric evaporative-demand stresses on surface-mine spoils;

(b) Determination of physiological tolerances of selected plant ecotypes to saline-alkaline stresses on various kinds of surface-mine spoils;

(c) Testing and evaluating hormone-stimulated rooting characteristics of native shrubs on abandoned, oversteep mine spoils; and

(d) Application of tissue-culturing techniques to develop increased tolerances of selected plant ecotypes to saline-alkaline stresses on surface-mine spoils.

c. *Impacts of Coal Development on Surface Resources.*—

(1) *Analytical method.*—An "analytical methodology" for analyzing the impacts of projected forecasts of coal development on surface resources was developed. Components consisted of: (a) basic assumptions, (b) steps in analysis, (c) rules for analysis, and (d) quantified definition of development levels (tables IV-2 and IV-3). It was recognized at the outset of the study that only subjective analyses were possible.

Sample areas selected for intensive analyses included:

Campbell County, Wyoming
Bighorn County, Montana
Rosebud County, Montana
Mercer County, North Dakota
Oliver County, North Dakota

Considering Mercer and Oliver Counties as a single area, the local areas represent four sample areas where intensive mining developments were projected. Collectively, these four sample areas represented 89 percent of coal production in CDP I for year 2000; 61 percent in CDP II; and 61 percent in CDP III. Thus, by far a majority of projected regional coal development is represented in the four sample areas.

Certain basic assumptions were prerequisite to the analyses. These were developed with the provision that additional ones as needed for particular resource considerations could be developed.

Some of the basic assumptions follow:

(a) All mined lands will, as a minimum, be returned to current vegetative cover and use.

(b) Within 1 year following mining, mined areas will have soil and overburden replaced approximately in the same sequence as existed prior to mining.

(c) Existing laws, regulations, and requirements will remain constant and in effect during the projection period (year 2000). (If present trends continue, environmental protection regulations will probably be more stringent.)

(d) Plant sites, reservoirs, transmission corridors, roads, towns, etc., will remain in place during all time frames through the projection period.

(e) Coal seam depths vary according to the particular formations where mines were sited.

(f) Assume the following acreages to be relegated to uses indicated for the duration of the projection period, dating from the time frame of establishment or operation:

Gasification plant site (250 MMCFD)	1,000 acres
Gasification plant reservoir	30 acres[43]
Power generation plant (1,025 to 1,250 MW)	100 acres
Power generation reservoir	50 acres

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[43] This estimate is too low for presently recognized needs.

Table IV-3. – *Total acres of lands impacted*[1] *in the NGP (cumulative by years)*

	1980	1985	2000	[2] 2020	[2] 2035
CDP I					
Mined land[3]	5,387	16,142	50,478	130,438	190,408
Plant facilities[4]	2,694	2,694	4,935	4,935	4,935
Ancillary facilities[5]	–	–	44,879	44,879	44,879
Total	8,081	18,836	100,292	180,252	240,222
CDP II					
Mined land[3]	5,500	19,409	100,795	364,255	561,850
Plant facilities[4]	2,993	11,706	26,227	26,227	26,227
Ancillary facilities[5]	–	–	82,518	82,518	82,518
Total	8,493	31,115	209,540	473,000	670,595
CDP III					
Mined land[3]	10,938	44,107	227,703	842,685	1,303,920
Plant facilities[4]	9,200	26,040	59,330	59,330	59,330
Ancillary facilities[5]	–	–	109,890	109,890	109,890
Total	20,138	70,147	396,923	1,011,905	1,473,140

[1] Acreages occupied by urban growth not determined, acreages occupied by ancillary facilities analyzed only for CDP III, years 2000 and 2035, and assuming all facilities would remain operational through 2035.

[2] Acreages for 2020-2035 are based on mines operating at year 2000 level of development.

[3] Acreages mined to dates indicated. No lands assumed to have been restored have been subtracted from these totals.

[4] Acreages occupied with plants, yards, and other facilities directly associated with plants and mines.

[5] Acreages occupied by railroads, highways, haul roads, transmission lines, aqueducts, and reservoirs were calculated only for year 2000.

Mine facility
acreages .... 150 acres

(a) No additional acreage allowed for either cleaning plant or tailings pond, if required.

(b) An acre-foot of coal (80 percent efficiency in recovery) yields 1,416 tons.

(c) Assume the following conditions for mined lands:

Campbell County, Wyoming.–Mining disturbance will affect only productive rangeland. Assume 4 acres per Animal Unit Month grazing. No cropland and no forest will be affected.

Bighorn County, Montana.–Mining disturbance will affect land resources thusly:

Table IV-3.—*Cumulative acres of projected habitat losses to coal development in the study area*[1]

Species	1980	1985	[2] 2000
CDP I			
Deer, mule, and white-tail	6,370	17,061	51,359
Antelope	5,478	14,914	44,227
Other big game[3]	167	257	527
Sage grouse	3,602	8,647	23,896
Sharp-tailed grouse	5,538	14,329	42,898
Hungarian partridge	5,116	13,287	39,270
Ring-necked pheasant	3,811	10,702	31,883
Turkey	826	1,976	5,939
CDP II			
Deer, mule, and white-tail	6,141	24,346	91,523
Antelope	5,259	20,548	73,662
Other big game[3]	167	257	527
Sage grouse	3,802	16,127	50,111
Sharp-tailed grouse	5,309	20,018	75,813
Hungarian partridge	4,867	18,974	69,784
Ring-necked pheasant	3,381	12,771	52,833
Turkey	826	1,976	10,509
CDP III			
Deer, mule, and white-tail	18,507	67,732	277,255
Antelope	15,007	58,594	210,842
Other big game[3]	167	257	2,216
Sage grouse	6,825	24,716	142,669
Sharp-tailed grouse	17,675	59,958	213,970
Hungarian partridge	15,907	54,836	177,795
Ring-necked pheasant	13,016	43,177	122,638
Turkey	5,809	17,103	83,208

[1] Includes only good- and medium-quality habitat lost, except other big game and turkey also include low-quality habitat lost to mine facilities and urban development. Various species ranges overlap, thus some acreages are listed more than once; therefore, acreages cannot be totaled.

[2] Based on the assumption that it takes 25 years to restore wildlife habitat, acreages strip mined between 1972-1975 are considered restored and have been subtracted from year 2000 totals.

[3] Includes in different ecosystems elk, black bear, moose, mountain goats, and bighorn sheep.

Rangeland, 80 percent; forest land, 10 percent; cropland, 10 percent, divided equally between wheat and alfalfa.

Rosebud County, Montana.—Mining disturbance will affect land resources thusly:

Rangeland, 80 percent; forest land, 15 percent; and cropland, 5 percent.

Mercer and Oliver Counties, North Dakota.—Best estimate available for probable land resource disturbance is:

Mercer County: 55 percent rangeland; 45 percent cropland.

Oliver County: 70 percent rangeland; 30 percent cropland.

Assume for purpose of analysis, combining both counties:

60 percent rangeland; 40 percent cropland. Assume cropland affected thusly: one-half wheat, one-fourth oats, one-fourth alfalfa hay.

(1) Assume 5 years as time requirement to return mined acreage to stable productive cropland. Assume 5 years to regenerate, by planting, forest land. Assume 10 years to return rangeland to stable and productive grazing condition. For such uses as wildlife habitat, assume a minimum of 25 years. It should be noted that these are estimates based on the experience of researchers working in the field of restoration technology in both the NGP and other parts of the U.S. These subjective estimates are not accepted by all researchers in the field and until further field studies to substantiate these estimates are conducted in the NGP these figures must be used with caution and be carefully qualified.

(2) *Summary of surface area to be disturbed.*—As previously discussed, there are several activities associated with coal development that remove land from use for agricultural, wildlife, and recreation purposes. These include the mine pit, storage and loading facilities, plant facilities, and storage reservoirs. In the operation of a mine, only portions of the area actually being mined can be returned to other productive uses during the life of the mine. The acreages committed to mining activities in the four sample areas are shown in tables IV-4, IV-5, IV-6, and IV-7. The cumulative acreage of land that has been mined and that land occupied by related facilities are shown for the periods 1980, 1985, and 2000 as gross acreage. The net acreage is the number of acres that have been committed to mines and related facility uses minus the land that would be rehabilitated to grazing or

Table IV-4.—*Campbell County land area*[1] *disturbed by mining and coal conversion facilities (cumulative totals by years)*

Acreage	1980	1985	2000
	CDP I		
Mines	448	2,032	8,126
Facilities	599	599	1,047
Gross	1,047	2,631	9,173
Rehabilitated		50	4,404
Net	1,047	2,581	4,769
	CDP II		
Mines	509	2,543	12,670
Facilities	749	2,229	2,528
Gross	1,258	4,772	15,198
Rehabilitated		65	5,984
Net	1,258	4,707	9,214
	CDP II		
Mines	509	3,511	27,665
Facilities	749	6,059	9,650
Gross	1,258	9,570	37,315
Rehabilitated		90	14,000
Net	1,258	9,480	23,315

[1] Total acreage in county is 3,033,281 acres.

Table IV-5.—*Bighorn County land area[1] disturbed by mining and coal conversion facilities (cumulative total by years)*

Acreage	1980	1985	2000
CDP I			
Mines	325	1,269	4,931
Facilities	300	300	1,050
Gross	625	1,569	5,981
Rehabilitated		37	2,525
Net	625	1,532	3,456
CDP II			
Mines	375	1,712	9,212
Facilities	450	2,812	4,587
Gross	825	4,524	13,799
Rehabilitated		44	4,256
Net	825	4,480	9,543
CDP III			
Mines	469	2,375	14,875
Facilities	1,631	4,144	12,719
Gross	2,100	6,519	27,594
Rehabilitated		56	6,587
Net	2,100	6,463	21,007

[1] Total acreage in county is 3,214,020 acres.

Table IV-6.—*Rosebud County land area[1] disturbed by mining and coal conversion facilities (cumulative total by years)*

Acreage	1980	1985	2000
CDP I			
Mines	2,256	4,894	14,912
Facilities	300	300	600
Gross	2,556	5,194	15,512
Rehabilitated		156	8,387
Net	2,556	5,038	7,125
CDP II			
Mines	2,256	5,425	23,437
Facilities	300	1,631	3,262
Gross	2,556	7,056	26,699
Rehabilitated		175	11,600
Net	2,556	6,881	15,099
CDP III			
Mines	2,537	7,862	45,169
Facilities	1,481	5,325	6,069
Gross	4,018	13,187	51,238
Rehabilitated		250	20,550
Net	4,018	12,937	30,578

[1] Total acreage in county is 3,220,320 acres.

cropland levels of productivity. Acreages committed to such uses as railroads, highways, transmission lines, aqueducts, reservoirs, and urban and residential development are not shown. These uses may equal or exceed the acreage shown in tables IV-4, IV-5, IV-6, and IV-7. The acreage committed to coal development activities including railroads, highways, transmission lines, aqueducts, and reservoirs for the total NGP region is shown in table IV-2.

(3) *Assessment of impacts.*—This section assesses impacts on the total NGP area based on the preceding five-county analysis.

(a) *Soils.*—The unique set of biotic, chemical, and physical properties constituting a given soil-plant system will be altered to an unknown extent. Soil structure will be altered, some soil micro-organisms will be lost, chemical properties will be changed, and water balances will be altered. The potential for erosion by wind and water will be increased to some unknown degree.

Those soils overlying lands not mined but used to support other associated facilities will be altered to some unknown degree. Assuming erosion is controlled

Table IV-7.—*Oliver and Mercer Counties land area[1] disturbed by mining and coal conversion facilities (cumulative total by years)*

Acreage	1980	1985	2000
CDP I			
Mines	3,283	6,000	16,600
Facilities	600	600	900
Gross	3,883	6,600	17,500
Rehabilitated		1,250	10,783
Net	3,883	5,350	6,717
CDP II			
Mines	3,283	6,708	28,333
Facilities	600	1,775	3,558
Gross	3,883	8,484	31,891
Rehabilitated		1,333	15,250
Net	3,883	7,150	16,651
CDP III			
Mines	2,537	7,862	45,169
Facilities	1,481	5,325	6,069
Gross	4,018	13,187	51,238
Rehabilitated		250	20,550
Net	4,018	12,937	30,688

[1] Total acreage in Oliver County is 460,819 acres; Mercer County 665,604.

and such soils are not contaminated with foreign materials they should be easier to revegetate than mined land.

The fate of trace elements and other substances contained in stack gases emitted from coal conversion plants has not been adequately studied and hence no estimate of their impact on soils and on the micro- and macro-organisms associated with them can be made. There is a need for additional investigation in this area.

Basic to all regional planning efforts related to energy development is an understanding and inventory of the basic resources of the region prior to development. Certainly one of the primary resource inventory needs is for detailed soil surveys that provide basic information concerning agricultural potential of soils, wildlife habitat potentials, and rehabilitation potential of areas that may be impacted.

(b) *Vegetation.*—Surface mining and associated plant and auxiliary structures will destroy existing vegetation. Its restoration will require extensive rehabilitation measures. The resource needs related to rehabilitation are discussed in Rehabilitation Potential (sec. 4-2(b)) of the NGP Surface Minable Lands. Additional needs are surveys of specie composition density and productivity at a level of detail that would describe those conditions that must be obtained by rehabilitation measures. Assuming rehabilitation technology is available, sources for seeds and plants suitable for rehabilitation needs must be developed.

As with soils, the impact of coal conversion emissions, particularly trace elements and SO_2 on vegetation are poorly understood and further study is needed. (See sec. 4-14.)

(c) *Agriculture.*—A more detailed examination of the impact of coal development on the agricultural economy is found in section 5-5.

(d) *Wildlife.*—The adverse impacts of coal development on the wildlife resources of the NGP will be associated with the direct loss of habitat (table IV-2) resulting from mining and associated activities and urban development and the disturbances caused by human activities. Intolerant species may abandon an area that can provide their physical needs (food, water, and shelter) when human activity interferes with certain behavioral activities necessary to their survival. Assessment of the impact of coal development activities on wildlife resources is compounded by the fact that animals occupy different habitat types at different times of the year and in some cases the day. For this reason the destruction of land in one area may obviate the use of land in another even though it has not been disturbed.

The classical example is a general shortage of winter deer range. Throughout the West there is an abundance of land that provides suitable habitat for deer during the spring, summer, and fall periods. These ranges are not utilized because the winter range is not sufficient to support the same population levels that could be supported by the other ranges. The winter range is therefore the factor that limits the deer population. Sharptail grouse have a similar dependence on breeding grounds.

As coal development occurs in a habitat type that presently limits the growth of a particular wildlife population, it will reduce that population in that habitat type as well as all other areas occupied by that population. Much information exists about the distribution, food habits, behavior, habitats, population trends, and migration patterns for game species, but a complete assessment of impacts on wildlife is not possible until baseline data on game species are collected and the impacts of coal mining and conversion on air, water, and vegetation are known.

The evaluation of the impact of coal development presented here is primarily the result of subjective analysis by persons who are familiar with NGP wildlife populations and their trends.

CDP I

In the CDP I, by 1985 some 17,000 acres will be lost to development and the human population will increase by 31,000 or 8 percent over the 1970 level. Except for some species, which are threatened or endangered and for some local wildlife populations, effects on fish and wildlife habitat in the region will be minor. The increased population may significantly degrade the habitat of the peregrine falcon, since the spring and fall migration habitat of this bird encompasses most of the northern prairie and more people will be occupying that habitat. There will be slight but important decreases in ring-necked pheasant and wild turkey habitat.

Hunting pressure for elk will increase both in the study area and to the west. Applications for moose, bighorn sheep, and mountain goat hunting permits will increase slightly because a greater percentage of the hunting population will qualify for resident hunting licenses. Hunting pressure on sage grouse and on ring-necked pheasant in the western part of the study area will increase so that the average hunter's success will noticeably decrease.

By the year 2000, development will have occupied more than 100,000 acres and 74,000 more people will reside in the area than did in 1970. It is probable that the peregrine falcon will no longer nest in Montana or Wyoming by that time, and spring and fall migrants will be reduced to a very rare visitor.

The endangered black-footed ferret and the western burrowing owl (status undetermined) are dependent on the black-tailed prairie dog. Coal development may cause significant decreases in the number of prairie dog towns, adversely affecting the ferret and owl.

In both Montana and Wyoming, large numbers of nonresidents hunt elk, deer, and antelope. As the number of resident hunters increases, they will likely demand a reduction in nonresident hunting permits, which if granted would reduce license fee revenues. This may result in an increase in resident hunter fees and a decrease in the outfitting and guiding industry.

Inexplicably, some people shoot hawks. The ferruginous hawk, prairie pigeon hawk, and prairie falcon are status-undetermined species resident in the study area. The projected human population increase by the year 2000 could cause serious hazard to these birds of prey.

Losses of game animal habitats will affect the wild turkey the most but sage grouse and ring-necked pheasants will lose significant habitat areas. Although only 5,900 acres of turkey habitat will be destroyed, the losses will occur in some of the better habitat areas. The sage grouse has experienced significant habitat losses recently because of large-scale sagebrush eradication programs. Under this forecast, an additional 24,000 acres of good- and medium-quality habitat will be lost. In view of trends, this is significant. In the region, better sagebrush habitat exists north and southwest of most developments.

Also, in view of present trends, the loss of an additional 5,800 acres of good- and medium-quality ring-necked pheasant habitat assumes significance, particularly to the west of the Dakotas.

Regionally, most hunting will be moderately changed by the year 2000. There will be an estimated 14,500 more deer hunters, 3,000 more antelope hunters, and 7,200 more elk hunters.

In both North Dakota and South Dakota nonresidents are allowed to hunt big game; however, the percentage of nonresident hunters is very low. Increases in the number of resident hunters in those states will result in decreasing opportunities to hunt deer and antelope.

Locally, popular fishing sites will become crowded, but regionally fishing demand will not exceed the supply.

CDP II

By 1985 more than 31,000 acres of land will have been altered. The area's population will increase by 135,000—a 36 percent increase over 1970. The population increase is nearly twice that of CDP I in the year 2000, but the land disturbance related to coal development is only one-third that projected for CDP I in the year 2000. It is believed human population increases will have greater impacts on fish and wildlife than will land disturbance attributable directly to coal development. For this year then, approximately twice the impacts on fish and wildlife resources will occur as projected for the CDP I, year 2000. One mitigating factor is that the impacts would have 15 fewer years to be realized; for some species and hunting situations, such as sage grouse hunting, that may be significant.

By the year 2000, CDP II, the area's human population will have swelled by 63 percent or 237,000 more people than in 1970. More than 209,000 acres will be committed to coal development. Adverse impacts on wildlife resources and on hunting will be significant.

Because of the magnitude of change, the extirpation of the peregrine falcon in the study area, both as a summer nester and as a spring and fall migrant, is predicted along with significant reductions in population levels of all raptors.

By year 2000, enough better habitat of white-tailed and mule deer, sage grouse, ring-necked pheasant, and wild turkey will have been destroyed to cause serious concern among game managers and to be readily noticed by the public. Hunting for all big-game species and some upland game (sage and sharp-tailed grouse, pheasant, turkey) will be seriously degraded.

Significant decreases in success ratios for deer, elk, and antelope will adversely affect the nonresident guiding and outfitting industry. Nonresidents traveling long distances would rather drive a little farther to areas where chances for harvesting game would be better.

CDP III

By the year 2000 in the CDP III, the area's human population will increase by 515,000 or 137 percent. Coal development will have destroyed almost 400,000 acres of wildlife habitat. The following impacts are projected:

(aa) Some 277,000 acres of good- and medium-quality deer habitat will be lost—almost 82,500 more deer hunters will compete with the current number of hunters for less deer.

(bb) Hunting for elk in Montana and Wyoming will be significantly degraded by loss of habitat and the addition of over 34,300 more resident elk hunters.

(cc) Sage grouse hunting in the region has had a long-term trend toward longer seasons and more liberal conditions. This trend will be abruptly reversed and by the year 2000 sage grouse hunting will be far more restricted.

(dd) Over 83,000 acres of turkey habitat will be destroyed. Turkey populations will be significantly reduced. A harvestable surplus, however, will be available annually and turkey hunting will continue, although under far more restricted circumstances than at present.

(ee) Raptors will loose 295,000 acres of hunting grounds and will be subject to intentional and unintentional persecution by half a million more people. Impacts on resident and wintering raptors will be significant; impacts on migrating birds of prey are speculative.

(ff) Local populations of perching birds will be eliminated. Effects on many species will be long term because it is unrealistic to project restoration of disturbed lands to natural levels of plant variety within a short time frame. Currently, the relationship of the hundreds of passerine species to the several ecosystems of the area is little understood by game biologist and land managers. The relationships probably serve a more important role in the prairie ecosystems than is widely appreciated.

(gg) Local populations of some endangered or threatened species will likely be extirpated. Any loss of individuals of these species would be disastrous. Candidates for losses include: American peregrine falcon, black-footed ferret, prairie falcon, prairie pigeon hawk, western burrowing owl, mountain plover, northern long-billed curlew, and ferruginous hawk.

(e) *Wild land.*—"Wild lands" are areas which generally appear to be undeveloped, unimproved, and not regularly cultivated and are usually capable of producing products or resources or supporting various uses while remaining essentially wild. These areas often possess steep and irregular topography and represent a segment of the landscape which appears essentially natural but may contain various impacts of man. Examples include desert, tundra, forest, badlands, grasslands, prairie, savanna, or pothole lands. They are presently devoted to uses which maintain existing ecosystems and may provide opportunities for the utilization of renewable resources at a sustained yield level.

These lands often contain cultural and historic values which are essential in the maintenance of a way of life. Types of use may include recreation, range forage, watershed, and sparse mineral extraction. These areas may contain abandoned farmlands, unsurfaced roads, pipelines, and transmission lines.

The designation of these lands as "wild lands" is not meant to imply they are suitable for Wilderness designation under the criteria established by the 1964 Wilderness Act. Wild land does include, however, those areas designated as "natural or primitive" by the Secretary of the Interior as well as other identified, undeveloped land areas.

Actual mining operations will have little effect on the inventoried wilderness-wild land resource. All impacts on existing areas of the Wilderness System will be caused indirectly by increased use or possible water modifications or developments. Increased use will result in some loss of opportunities for solitude within the wildernesses. Visitors seeking solitude may have to penetrate further or pick seasons when use is light.

No proposed units to the National Wilderness Preservation System are directly affected by the projected mining operations. However, impacts will likely occur as a result of increased recreational use or development projects affecting waterflows through these areas.

(f) *Scenery.* Analysis of impacts on scenery is limited to the four sample areas. An impact analysis on a regional basis was impracticable because of the inherent difficulty of attempting to equate qualities among entirely different types of scenery; e.g., scattered pines on hills near Colstrip, Montana, versus the grasslands of the Knife River Valley in North Dakota.

Within the four sample areas, smoke plumes from power and conversion plants would have the greatest impact on scenic views in the eastern portion of Bighorn County, Montana. In Rosebud County, Montana, it will be the Yellowstone River Breaks that are impacted by smoke from energy developments. Open country north of the Yellowstone will sustain little scenic impact. Scattered pine and park areas south of the Yellowstone will experience serious impacts on scenic values resulting from both mining activities and energy-producing plants.

In Campbell County, Wyoming, power and gasification plants will create fairly low impacts over wide areas, principally affecting visual air quality. Scenic impacts in Mercer and Oliver Counties, North Dakota, will be severe because of the intensity of development. Initially, the chief impacts will be physical, but later visual air quality will decline.

C. Water Resources

4-3. *General.* The conversion of coal to electricity or synthetic gas in the NGP is intricately linked to water supplies. Without sufficient water at a reasonable price, coal conversion may be constrained or foregone in some instances. Water diversions for coal development will compete, in some areas, with existing uses and their future growth. In addition to water depletions, upstream users will discharge effluents that may affect the quality of water for downstream users.

These are but a few of the interrelationships between energy development and water. Listed below are questions concerning water use in the NGP. The principal purpose of this section is to highlight these questions and to provide information based on our current state of knowledge.

- What are the existing water resources in the NGP and how are they being used?
- What will be the future demands on these resources?
- How much water is available for energy development?
- What will water cost?
- What will be the economic and environmental impacts of increased water use for energy resource development?
- How will energy resource development affect water quality?

4-4. ***Historic Background.*** Water has played an important role in the development of the semiarid NGP. Early exploration and settlements followed the river networks which comprise the Missouri River Basin. With the introduction of the windmill, a greater dispersion of the settlements was allowed by ensuring the farmer a convenient water supply for his household and a herd of livestock.

Overriding other factors in the pattern of water supply and use is a very wide fluctuation in flows from season to season and from wet year to dry. Many significant rivers dry up for long stretches during drought years. Even in normal years, a high percentage of the total flow occurs during late spring. On the downstream eastern edge of the NGP and at a few scattered sites within the region, water is impounded to assure more reliable supplies

However, the Yellowstone River and all its tributaries, with the exception of the Wind-Bighorn and Tongue Rivers, are largely unregulated and undisturbed by impoundments.

Water is a commodity of considerable value and a system of laws has evolved to determine who has the right to use of the water. Water laws based on both the appropriation rights doctrine and the riparian rights doctrine have been adopted by the NGP States.

The *common-law doctrine of riparian rights* is based primarily on the ownership of land and uses of water thereon contiguous to the stream. Under the Riparian Rights Doctrine, the owner of land contiguous to a natural stream or natural lake may use the waters for such purposes and in such quantities as he chooses, providing he does not appreciably diminish the flow or impair the quality of water for downstream users. Such rights are not expressed in specific quantities of water unless they have been apportioned by the court. There is no priority of right although domestic use and the watering of domestic livestock are generally considered preferential uses. Riparian rights are not usually transferable to land not contiguous to the stream or lake from which the water is being drawn.

Under the *appropriation rights doctrine* the beneficial use (as defined by each State) of water is the basis, the measure, and the limit of the water right. The first beneficial appropriation is prior in right. Appropriations are for a definite rate of diversion or storage and often the total seasonal or annual quantity is specified. The appropriation right is obtained and sustained only by actual and continuous beneficial use. Failure to make beneficial use of an appropriation may result in its loss. Appropriated water may be used either on land contiguous to or a distance from the water source.

4-5. ***Surface Waterflow Conditions.***—A number of rivers and basins in the NGP region were and are being studied to determine reliable flow condition information.

a. *Yellowstone River Basin, Montana and Wyoming.*—The highest streamflow rates in the Yellowstone River Basin (fig. IV-3) occur in May and June and are produced by snowmelt and rainfall in the mountainous areas. The average flows that occur during this period are 5 to 10 times the average flows that occur in fall and winter months. Critically low flows, sometimes approaching no flows in some tributaries and streams, occasionally occur in the fall period causing serious water use problems for irrigators and adversely affecting fish and wildlife resources. Significantly less water is available during these drought conditions than shown in figure IV-3. For example, the lowest recorded average June flow in the Tongue River at Miles City, Montana, is 5,997 acre-feet as compared with the historic average of 115,644 acre-feet. The Bighorn River is the only major stream in the Yellowstone Basin that is regulated. This is accomplished by controlled storage in Yellowtail and Boysen Reservoirs which are primarily operated for power generation, flood control, and irrigation purposes. Monthly average flow releases are shown in figure IV-4.

b. *Western Dakota Tributaries of the Upper Missouri River.*—Unlike the Yellowstone Basin, the western Dakota tributaries of the upper Missouri River are relatively short and do not drain mountainous areas. Earlier snowmelt (than in the high elevations of the Yellowstone watershed) in this plains region causes relatively high flows as early as March and April in the Little Missouri, Knife, Heart, and Cannonball Rivers (fig. IV-5). Overall, the flows in these rivers are substantially less than in the Yellowstone Basin and drought periods, intensified by the small watershed area, seriously constrain water use and productivity of aquatic resources.

c. *Main Stem Missouri River.*—The Missouri River flows within the NGP study area are not subject to much seasonal variation as they are regulated at Fort Peck, Garrison, and Oahe Dams (plate 7) for purposes such as electric power generation, flood control, and downstream navigation. Monthly average flows released from Garrison are shown in figure IV-6.

The demand for stored water during years with low amounts of precipitation has contributed to the development of the large water impoundments for water storage in the

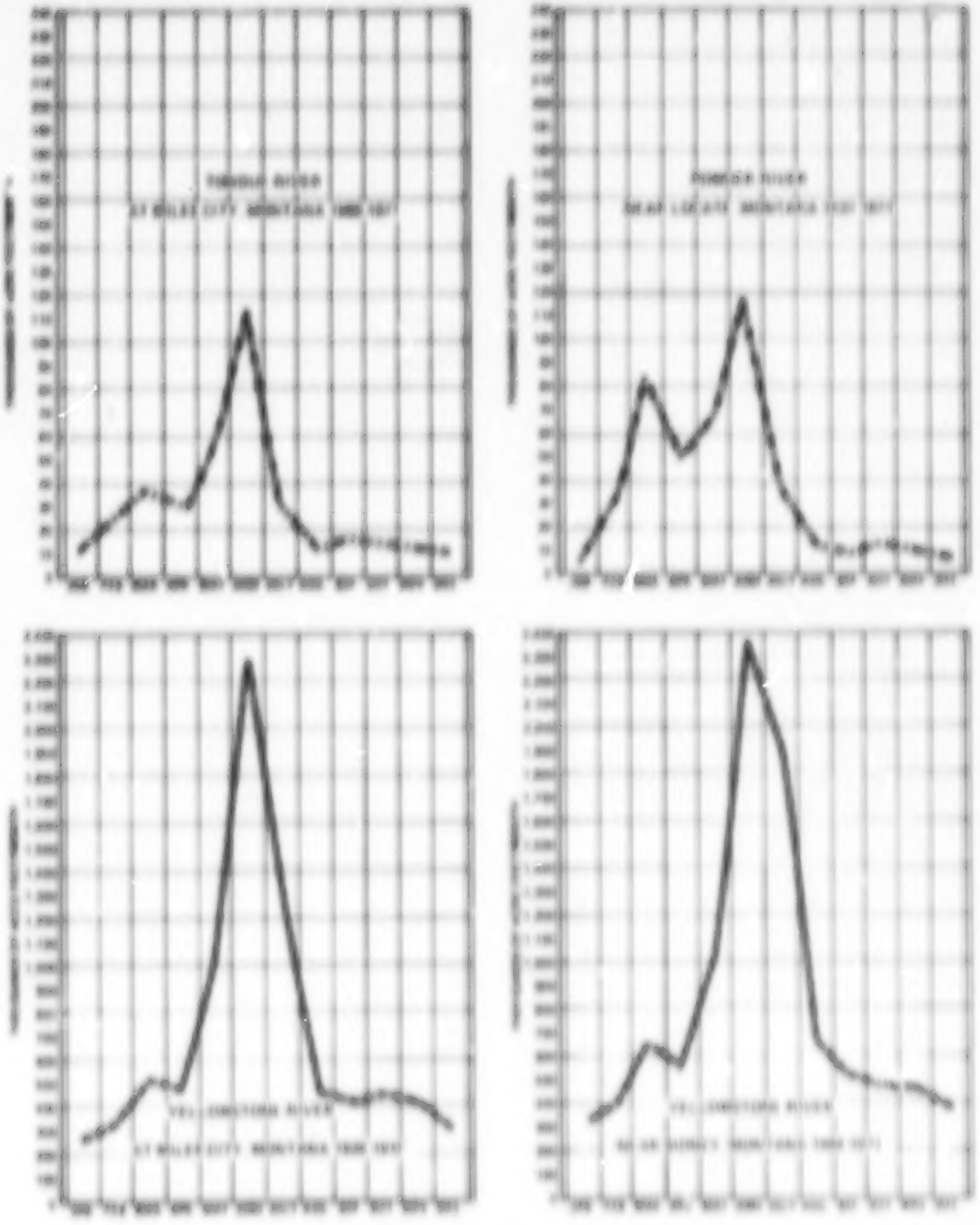


Figure IV-3. Historic Yellowstone River Basin Flows

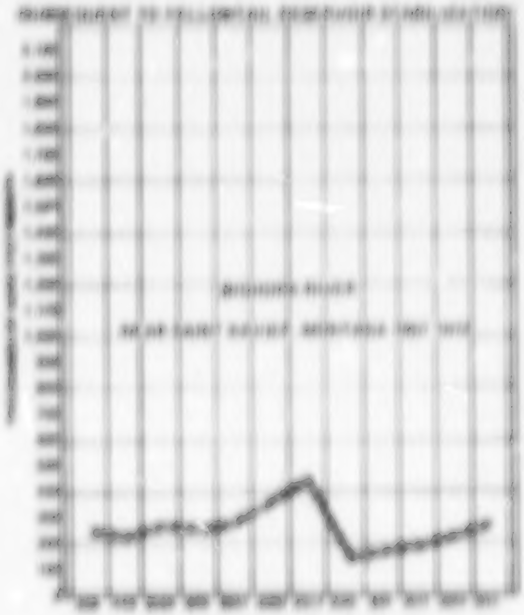


Figure IV-6. Releases from Yellowtail Dam.

NGP study area referred to above (Boysen, Yellowtail, Fort Peck, Garrison (Lake Sakakawea), and Oahe). One purpose of these reservoirs is to supplement water supplies to users along the Bighorn, Yellowstone, and Missouri Rivers. Demand for water can, however, still exceed streamflow and storage releases in selected tributaries, which in many years become completely dewatered for some time (table IV-6). Such conditions might be prevented if water resources were managed to protect aquatic and riparian habitat.

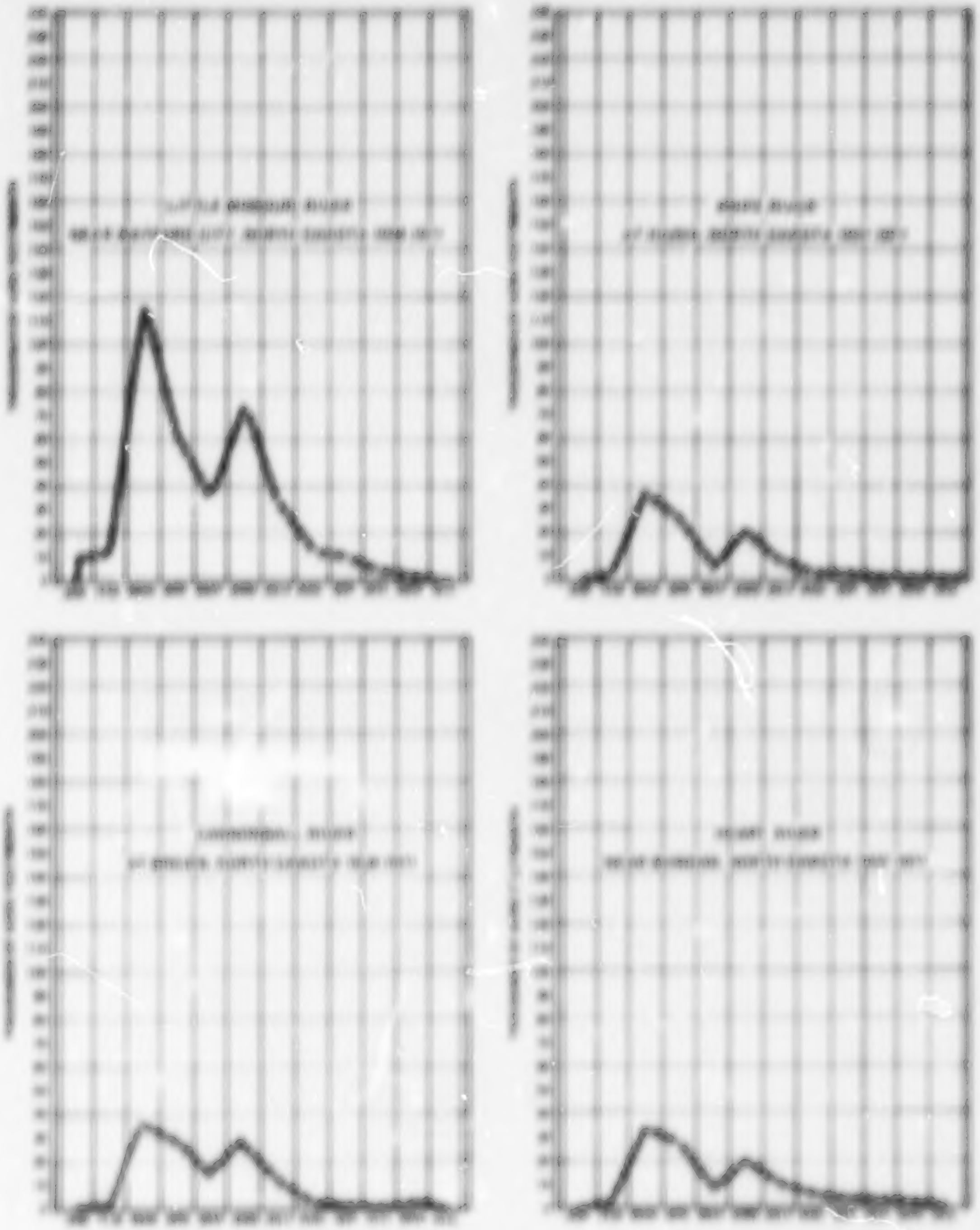
6-6. *Current Trends and Uses.*–Irrigation consumes a significant portion of water in the NGP region. In the Yellowstone River Basin of Montana and Wyoming it is estimated that about 1.25 million acres of farmland are under irrigation. A total of approximately 2.26 million acres are irrigated above Lake Sakakawea in the Missouri and Yellowstone River Basins. The initial stages of the planned Garrison and Oahe irrigation projects, when completed, will irrigate approximately 440,000 acres in the Dakotas and utilize about 1.17 million acre-feet of water from Lakes Sakakawea and Oahe. While irrigation depletions require only a small amount of the total water supply produced in the area, seasonal uses of water for irrigation reduce flows in some streams to a point where municipal water supply systems are impaired and aquatic and riparian habitats are degraded.

Loss of water through evaporation from large reservoirs exceeds all other consumptive uses combined (fig. IV-7). Practices such as contouring, terracing and erosion control, and small impoundments for fisheries, recreation, stock watering, and small irrigation projects are also shown to be significant water consumers.

In addition to consumptive water use, there are many uses generally regarded as nonconsumptive, such as hydroelectric power generation, navigation, fish and wildlife, recreation, and esthetics. Some of these, such as hydropower and navigation, do not directly consume water. They sometimes, however, require impoundment which causes a water loss through evaporation. Whenever a stream is dammed to impound water, prior rights of use must be recognized and not impaired. With the exception of Montana, these rights or beneficial uses exclude fish and wildlife, recreation, and esthetic values.

Approximately 87 percent, or 2,080 megawatts, of the hydropower capacity, which is in the study area or affected by it, is installed at the six main stem dams on the Missouri River: Fort Peck in Montana, Garrison in North Dakota, and Oahe, Big Bend, Fort Randall, and Gavins Point in South Dakota. Total hydropower capacity in the Yellowstone Basin is 296 megawatts, 250 megawatts of which are at Yellowtail Dam on the Bighorn River.

There is no major commercial navigation in the Missouri Basin above Sioux City, Iowa; however, downstream barge-tow transportation of farm products depends upon water stored behind the Missouri main stem dams. Indications are that under present conditions a rate of flow of 25,000 to 35,000 cubic feet per second would be adequate to support a 9-foot navigation channel downstream of Sioux City with nominal dredging. This would require up to 12 to 15 million acre-feet of water during the navigation season which may be as long as 8 months.


LITTLE MISSOURI RIVER
KNIFE RIVER
CANNONBALL RIVER
HEART RIVER

[illegible]

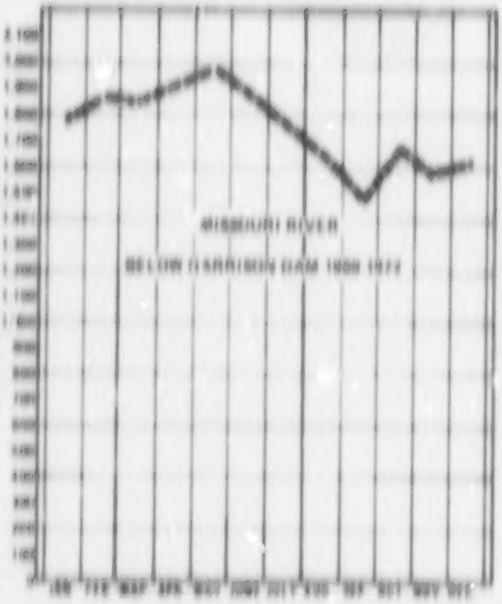


Figure IV-6. Releases from Garrison Dam.

The thrust of new development is currently shifting water use from agriculture to industry. (It is possible that this situation will change dramatically or be compounded by the need for increased food production.) Indications of this shift are the growth in the number of Federal Industrial Water Option Contracts and industrial applications for water storage sites in the NGP.

Since 1967, option contracts to purchase federally owned storage water have been made or are pending with many companies. An option contract is bought for a relatively nominal charge by the purchaser and will reserve, for a certain period, water in storage for future use. Additional applications for contracts to purchase federally owned storage water have been received but are not yet in effect. Table IV-9 summarized this information for both existing and potential (Moorhead Reservoir, New Tongue River Reservoir, and Yellowstone River) storage sites. It should be noted that these data indicate potential future

Table IV-8.—*Days for which flows of less than 0.1 ft³/second were recorded and average annual flow in the Yellowstone and Western Dakota tributaries*

River location	Period of record	Less than 0.1 ft³/second flow recorded: Average number of days of occurrence in a year	Less than 0.1 ft³/second flow recorded: Annual percent occurrence	Average annual flow for period of record (cfs)
Tongue River at Miles City, Montana	1938-1971	[1] 0.0	[1] 0	417
Powder River near Locate, Montana	1939-1971	1.6	0.4	609
Little Missouri River near Watford City, North Dakota	1935-1971	34.7	9	583
Knife River at Hazen, North Dakota	1930-1971	2.7	0.7	177
Heart River near Mandan, North Dakota	1929-1971	16.4	4	280
Cannonball River at Breien, North Dakota	1935-1971	22.3	6	236

[1] Zero flow recorded for July 9-19, August 13, 14, and September 28, 1940.

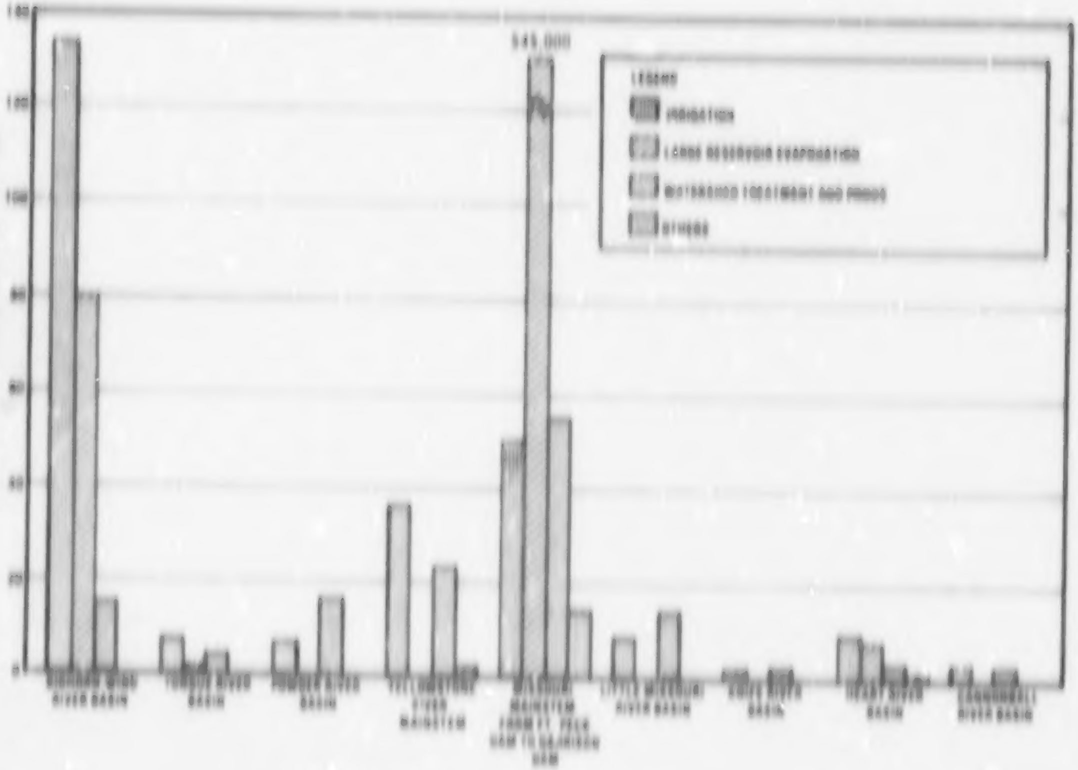


Figure IV-7. Increase in annual average depletion from 1949 to 1970.

water use involving a degree of uncertainty for the companies and, as such, represent speculation similar to that of buying land underlaid by coal.

The shift away from the use of water for new irrigation is partly the result of the new standards for federally funded water projects for which discount rates are now 5-7/8 percent. Under the new standards, considering the relatively low net farm income and high construction cost and the current discount rate, the probability of new federally funded irrigation projects is very low. There will undoubtedly be additional private and State-assisted irrigation in the future, and projects presently under construction may be expected to continue.

4-7. *Water Demand*.—a. *Water for Coal Conversion*.—To conduct water supply studies for coal development and assess the impacts of such water development, assumptions pertaining to the quantity of water used at powerplants and gasification plants were necessary. The original assumptions made in the study were that:

(1) Powerplants require 19,000 acre-feet of water per year per 1,000 megawatts generated.

(2) Gasification plants producing 250 MMSCF/day require 30,000 acre-feet per year.[43]

These assumptions were made early in 1973. Since then new information has been developed indicating these figures to be too

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[43] Goldman, E. and Kelleher, J.: Water Reuse in Fossil Fueled Power Stations. In: Complete Water Reuse, Cecil, L. K. (ed.). New York, N.Y.: American Institute of Chemical Engineers. April 1973. pp. 180-185.

Table IV-9.—*Federal industrial water option contracts and applications as of October 1974*

Water source[1]	Active storage[2]	Water option contracts in effect (acre-ft per year)	Water option contract applications, (acre-ft per year)
Boysen Reservoir, Wind River, Wyoming	700,300	85,000	9,000
Yellowtail Reservoir, Bighorn River, Montana	872,700	623,000	549,000
Moorhead Reservoir (potential), Powder River, Montana	275,000	0	220,000
Fort Peck Reservoir,[3] Missouri River, Montana	13,600,000	0	732,000
Lake Sakakawea,[3] Missouri River, North Dakota	17,700,000	0	227,000
Lake Oahe, Missouri River, North/South Dakota	16,900,000	0	125,000
Lake Tschida, Heart River, North Dakota	69,000	0	18,000
Shadehill Reservoir, Grand River, South Dakota	84,000	0	19,000
Yellowstone River and tributaries, Montana		0	[4] 630,000
Totals in Upper Missouri Basin		712,175	2,529,000

[1] Water Work Group Report.

[2] Does not include exclusive flood storage space.

[3] Main stem storage.

[4] These applications are based on the assumption that federally funded storage reservoirs on the Yellowstone or its tributaries will be built.

high. The issue is discussed below and the revised estimates of water needs are presented, however, all of the water supply studies and impact assessments were based on the original assumptions. The reader is cautioned to keep this in mind when reading the parts of this report that are related to impacts of water development or cost of water development.

A variety of cooling systems for powerplants are available and each system has a different water requirement. In the NGP a typical water-cooled 1,000-megawatt coal-fired powerplant will utilize water for several processes. Most of the water will be used for evaporative cooling. This process will utilize around 10,000 to 12,000 acre-feet/year. Anywhere from 700 to 1,000 acre-feet will be consumed for ash handling depending on the methods used. If a wet SO_2 scrubber is used, it will consume an additional 3,000 acre-feet/year. There are other incidental water needs but they are minor compared to the above uses. The total consumptive water requirement for a 1,000-megawatt plant ranges between 12,000 and 15,000 acre-feet/year. The lower figure represents a plant that does not utilize a wet SO_2 scrubber.

Dry cooling systems which use air instead of water may significantly reduce the need for water. It is difficult to estimate the water needs for a 1,000-megawatt plant because only one dry cooling plant has been built in the NGP and it is less than 30 megawatts (construction of a 330-megawatt dry-cooled plant is underway at the same location). However, water usage estimates range from 500 to 5,000 acre-feet/year for a 1,000-megawatt plant. Though dry cooling conserves water, its capital and operating costs are significantly higher than for wet cooling. Dry cooling is economically preferable to wet cooling only where the cost of water is substantial. Interpolation from two recent studies[44] [45] suggests that when delivered water costs are from about $200 to $250 per acre-foot, dry cooling then becomes economically competitive with wet cooling. For CDP I the delivered cost of water is less than $200 per acre-foot for all of the six powerplant sites. In CDP II those powerplants sited more than 100 miles from the point of diversion may find that dry cooling is more economical. In CDP III water costs are slightly lower because of economies of scale; thus, dry cooling becomes economic somewhere beyond 150 miles from the diversion point. (This is a highly variable number which is dependent on pumping lifts, quantity diverted, and length of conduit.) If ground water could be combined with a wet cooling process, this would probably be more economical than dry cooling. Hybrid wet/dry cooling systems may also offer economies on water use but were not evaluated in this study.

Water is also necessary for the production of synthetic natural gas from coal. Precise quantification of water demand is difficult, as there are no coal gasification plants operating in the United States and the final quantification of the water demand depends upon a technology yet to be developed.

Nevertheless, estimates of water needs have been made for the Lurgi-based process by process developers and plant designers. The three uses for water in coal gasification are as a source of hydrogen in the gasification reaction, for process steam, and for cooling purposes. The atomic hydrogen content of the methane product in coal gasification must come from water. If it is assumed that all the atomic hydrogen contained in water is eventually attached to carbon from the coal to produce methane (and that the product gas is pure methane), some 3,400 acre-feet/year of water would be required for a 250 MMSCF/day gasification plant. In reality, this process will not be completely efficient, so somewhat more water would be required. On the other hand, water in wet coal may supply some of this requirement, thus reducing the need for added water. The Office of Coal Research has estimated a water requirement of 4,000 acre-feet/year for a 250 MMSCF/day plant,[46] but exact requirements will depend on the particular coal and process used.

The cooling requirements associated with coal gasification as well as numerous miscellaneous water uses similar to a powerplant are also significant. Estimates of total water required for a 250 MMSCF/day plant have ranged as high as 30,000 acre-feet/year[47] when total evaporative cooling is used.

Utilizing the design plans of those few gasification plants proposed to be built in the United States for estimating plant water requirement, the range can be narrowed from 8,000 to 12,000 acre-feet/year. This assumes both wet and dry cooling systems for the various plant systems. A better understanding of the Lurgi-based process on western coals, coupled with moderate advances in technology, may further lower this requirement to a range of 6,000 to 10,000 acre-feet/year. Currently, a "best estimate" for the NGP would appear to be 9,500 acre-feet/year for a 250 MMSCF/day plant. If significant additional water is used, discharges would result.

Table IV-10 shows a comparison of regional water requirements for various use alternatives

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[44] Townsend, Stuart and Van Lanen, James, "An Economic Analysis of Alternative Technologies for Cooling Thermal Electric Generating Plants in the Fort Union Coal Region," Montana Agricultural Experiment Station, Montana State University, Bozeman, Montana, 1974.

[45] Water Quality Subgroup Report.

[46] Office of Coal Research, Annual Report, 1974, pp. 31-34.

[47] Final Report of the Supply Technical Advisory Task Force-Synthetic Gas-Coal, prepared for the National Gas Survey of the Federal Power Commission, April 1973.

Table IV-10.—*Comparison of potential water requirements for each CDP during years 1980, 1985, and 2000*

Year	Installed generation capacity megawatts[1]	Number synthetic natural gas plants (SNG)	High water[2] use requirement, acre-ft/yr	Medium water use requirement,[3] acre-ft/yr	Low water use requirement,[4] acre-ft/yr
			CDP I		
1980	5,513	0	98,000	62,000	28,000
1985	6,613	0	119,000	75,000	33,000
2000	13,100	0	243,000	153,000	66,000
			CDP II		
1980	5,513	0	98,000	62,000	28,000
1985	6,613	7	329,000	142,000	75,000
2000	19,400	16	843,000	361,000	139,000
			CDP III		
1980	5,513	7	308,000	129,000	70,000
1985	6,613	20	719,000	263,000	153,000
2000	19,400	41	1,593,000	618,000	343,000

[1] Does not include 6,740 megawatts of installed generation capacity listed in table III-10 which are outside of the 63-county impact area but does include 330 megawatts of air-cooled capacity.

[2] Assumes 30,000 acre-feet/year for a gasification plant and 19,000 acre-feet/year for 1,000 megawatts of electricity. This rate of use results in a 20,000 acre-feet/year discharge from gasification plants and 5,000 acre-feet/year from a powerplant.

[3] Assumes 9,500 acre-feet/year for a gasification plant and 12,000 acre-feet/year for 1,000 megawatts of electricity. At these rates of use plants would discharge almost no effluents. Those that are discharged could be contained in evaporative ponds.

[4] Assumes 6,000 acre-feet/year for a gasification plant and 5,000 acre-feet/year (dry cooling) for 1,000 megawatts of electricity.

and the levels of coal development assumed in each CDP.

b. *Water for Municipal and Domestic Use.* Utilizing NGPRP estimates for increases in population resulting from development of new coal mines, powerplants, gasification plants, and associated growth, an estimate of municipal water needs can be developed as shown in Table IV-11. The estimated water needs are based on an assumed municipal water requirement of 125 gallons per person per day. The range in municipal water requirements is generally between 100 (Gillette, Wyoming) and 200 (Billings, Montana; Bismarck, North Dakota) gallons per person per day. It should be noted that historically as population increases, per capita water consumption increases.

c. *Water for Revegetation of Mined Lands.* Revegetation of strip-mined lands may also require water for irrigation, particularly during drought conditions. Although revegetation may be accomplished without irrigation when rainfall amounts are adequate, water would have to be allocated for revegetation purposes if revegetation was to be initiated during possible drought periods. Assuming that the minimum annual

Table IV-11.—*Estimated additional municipal water needs for the region by 2000*

	Projected population increase	Million gallons per day	Acre-feet per year
CDP I	74,000	9.25	10,300
CDP II	237,000	29.63	33,100
CDP III	515,000	64.37	71,800

precipitation requirement is 12 inches (the average rainfall in some areas) and that 2 consecutive years of normal precipitation are required for revegetation of grasses and that drought conditions may provide only 4 inches of precipitation, an estimate of the supplemental revegetation water requirement can be made. By year 2000, the high level of coal development (CDP III) assumes that 30,750 new acres of land would be mined every year. Assuming that at least 2 consecutive years are needed for establishment of grasses, in a drought year twice this amount or 61,500 acres would require irrigation. Therefore, 8 inches (12 inches minus 4 inches) of irrigation over this land area would require 41,200 acre-feet annually. Table IV-12 summarizes this water requirement for the other coal development profiles. A mine disturbing approximately 700 acres per year (assume a thin coal seam) would need 465 acre-feet each year while a single mine disturbing 100 acres per year (assume a thick coal seam) would need only 67 acre-feet per year. Although this amount of water probably would not be used every year (less water would be needed when rainfall exceeded 4 inches), a system to supply water to mine sites for use in revegetation during drought conditions may be needed along with the appropriate water rights. Such a system could use diverted surface water or shallow ground water or in some cases water recovered from the mine pit.

As this use of water will correspond to drought conditions when diverted surface water may be in short supply for competing uses, storage of water at or available to the mine site for revegetation purposes may be necessary. If the "revegetation" water rights are "junior," then revegetation efforts could severely suffer.

d. *Water for Slurry Pipeline Export.*—Slurry pipeline export of coal also represents a potential water use. Although there is some uncertainty about the water requirements for this use, data from the slurry pipeline currently being planned for the Gillette area indicate that the annual water requirement will be 600 to 800 acre-feet per million tons of coal transported. Using this water requirement, table IV-13 shows the amounts of water required for slurry pipeline transport of half or all mined coal projected for export.

e. *Total Potential Water Demand.*—A perspective of the potential total water requirement for the region for the year 2000 can be gained by combining the various water demands discussed previously with those projected by the Missouri River Basin Interagency Committee for agriculture for the

Table IV-12.—*Water requirement for revegetation, year 2000*[1]

	Acres being mined, acres/year	Area being irrigated, acres/year	Maximum supplemental irrigation requirement, acre-feet/year
CDP I	4,000	8,000	5,300
CDP II	13,200	26,400	17,700
CDP III	30,750	61,500	41,500

[1] Assumes 8 inches of irrigation water per acre of mined lands. During normal periods of precipitation no supplemental irrigation may be needed.

Table IV-13.—*Water requirements for slurry pipeline export of coal, year 2000*[1]

	Coal exported, million tons	Water need when all export coal is shipped by slurry pipeline, acre-feet/year	Water need when one-half of export coal is shipped by slurry pipeline, acre-feet/year
CDP I	54	37,800	18,900
CDP II	110	77,000	38,500
CDP III	534	373,800	186,900

[1] Calculations of water required based on 700 acre-feet per million tons of coal transported.

Missouri Basin above the confluence of the Missouri and Yellowstone and Yellowstone Basin and the Western Dakota tributaries (Table IV-14). Montana states a significantly higher requirement for irrigation water from the Yellowstone. Not included are the depletions which may result from development of the Garrison and Oahe projects. Initial phases of these two irrigation projects are estimated to use 866,000 acre-feet and 303,200 acre-feet, respectively. Ultimate phase depletion would equal 3,218,100 acre-feet.

Assuming institutional requirements or water costs promote some conservation of water by coal conversion plants, then the medium water use estimates in Table IV-10 give the most likely estimates of the power and gasification plants water requirements. By adding these industrial plant medium water use needs to projected municipal, revegetation, and slurry pipeline water needs, an estimate of the total water requirements for coal development in the region can be determined as shown in Table IV-15.

Not included in the total potential water demand summarized in Table IV-15 is potential consumptive use for fishery and wildlife habitat improvements. In the Missouri River Basin Comprehensive Framework Study an analysis was made of the opportunities for wildlife and fisheries habitat improvements to meet long-term needs. While many of the opportunities involved the quantity and quality of instream flows and thus were essentially nonconsumptive, there were other improvements which did involve consumptive uses.

In the Western Dakota's Tributaries Subbasin fishery habitat improvement programs, there is a potential to consume 18,290 acre-feet annually while wildlife programs would consume 1,600 acre-feet.

In the Missouri Main Stem Subbasin no fishery consumption is estimated but wildlife habitat improvements could consume up to 247,000 acre-feet annually. This assumes extensive wetlands development in connection with the Garrison Diversion Project and the Oahe irrigation unit as well as intensive wetlands development in the Sun Prairie, Telegraph Creek, and Three Forks areas of Montana.

In the Yellowstone Subbasin no consumptive uses for fishery habitat development are contemplated. Potential wildlife developments could consume 53,000 acre-feet annually with major waterfowl habitat development in Big Lake Basin and near the mouth of the Bighorn River.

If all these habitat improvement programs were completed, it would result in a total consumptive use of 319,890 acre-feet of water per year.

Although these estimates of the consumptive water needs for fish and wildlife habitat development are tentative in nature, they give some usable data as to the general magnitude of these water needs.

4-8. *Water Availability*.—In exploring the

Table IV-14.—*MRIAC projected surface water demands for year 2000*[1]

	Upper Missouri Basin (above Lake Sakakawea)	Yellowstone Basin	Western Dakota tributaries	Total
	All in thousands of acre-feet per year			
Cropland irrigation:				
Full service	512.2	683.6	455.0	1,650.8
Supplemental	116.0	102.5	0	218.5
Livestock	24.2	23.7	26.0	73.9
Evaporation:				
Large reservoir	20	21.7	28.0	69.7
Small reservoir	17.7	37.3	143.0	198.0
Ponds	14.8	35.2	10.0	60.0
Total	704.9	904.0	662.0	2,270.9

[1] Missouri River Basin Interagency Committee Comp Fram Study, Vol 6, Hydrologic Analysis and Projections Appendix, tables 23, 24, and 25, pp. 130-131, Dec. 1971.

Table IV-15.—*Coal development related water demands for 2000—CDP III*[1] *(medium water use estimates in acre-feet)*

	Demand	Depleted	Return
Coal conversion:			
Gasification	389,000	389,000	0
Coal-fired electric	229,000	229,000	0
Municipal	69,300	13,900	55,400
Revegetation[2]	41,500	30,700	10,300
Slurry pipeline[3]	186,900	186,900	0
Total	915,700	844,700	65,700

[1] Evaporation from new reservoirs not an item as none are forecast for CDP III in year 2000.

[2] Maximum demand during drought. (Average annual demand will probably be considerably less during normal and wet years.)

[3] Assumes 50 percent of exported coal shipped by slurry pipeline. (Such water would be a depletion from the study area.)

methods of supplying water to the various levels of coal development activities theorized in each CDP, the diversion was constrained so as not to deplete flow to a point that would significantly diminish the aquatic and esthetic values associated with NGP streams. In developing the hypothetical water supply system, this constraint was applied in all cases except for parts of the Bighorn and Yellowstone Rivers in CDP III. The flows needed to maintain these values are referred to in this report as "suggested streamflows."[44] It should be noted that the "suggested streamflows" are estimates. To determine adequate streamflows requires extensive field investigation. Even if these flows are adequate to meet instream needs, lack of legal recognition of these uses as a beneficial use of water, water rights, and interstate compacts in all States except Montana may preclude the use of water for these purposes.

In discussing the subject of water availability, the region can be arbitrarily divided into three areas: (1) the Yellowstone River Basin, (2) the main stem Missouri upstream from Oahe Reservoir, and (3) the western Dakota tributaries.

1. *Yellowstone River Basin*.—The Yellowstone River and its tributaries are largely free-flowing, unregulated streams. The major exception is the Wind-Bighorn River which has two impoundments and the State of Montana Tongue River Reservoir. Two of these reservoirs, Boysen and Yellowtail Reservoirs, have a combined storage capacity of 1,918,000 acre-feet. These reservoirs contain the major portion of storage from which surface water could be made available for coal development in the Yellowstone River Basin. In addition to this existing source of water, the potential of supplying water from three hypothetical reservoirs was studied. These included two reservoirs, the New Tongue Reservoir on the Tongue River and the Moorhead Reservoir on the Powder River, to supply some CDP I requirements, and one reservoir, Pumpkin Creek, to supply some CDP II requirements. Table IV-16 shows the amount of water that was determined to be available (within the constraints imposed for instream needs) at particular points of diversion and the water requirements for the various CDP's.[45]

The amounts of water shown as available on table IV-16 are those amounts that would have been available annually during the driest period of record without any shortages occurring. As the table shows, the water requirements generated by the CDP I and II levels of coal development could be met by providing a modest amount of new storage. However, the water requirements generated by the CDP III level of development could not be met without depleting flows in the Bighorn River from Hardin, Montana, to its confluence with the Yellowstone to a level below that necessary to maintain intrinsic stream values *unless the medium water use estimates are assumed*. Under these conservation water use assumptions, new reservoirs would not be required and there would also be an additional 49,000 acre-feet of water available for diversion from the Bighorn River at Hardin. This amount of water would exceed that required by the attendant municipal and domestic requirements and the irrigation needs associated with revegetation of disturbed lands.

Although it can be concluded, based on medium use estimates, that there is sufficient surface water in storage in the Yellowstone Basin to supply the needs of coal development up to the year 2000, it must be recognized that other water demands, particularly those for new irrigation supplies, will compete for this water. Therefore, the Yellowstone Basin should be considered an area where uncommitted and therefore available stored water is scarce.

It is estimated that approximately 9.9 million acre-feet of water annually could be developed for use at the boundary line between the upper and lower Missouri River Basin. This figure is the amount of water available for additional development by Indians and non-Indians including the amount already established as a requirement for Indian use in Montana and Wyoming and the amounts committed to authorized Bureau of Reclamation projects. The derivation of this number is shown in the following analysis:

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[44] Instream needs appendix to the Water Work Group Report.

[45] Water Work Group Report.

Table IV-16.—*Water availability in the Yellowstone Basin*

Reservoir	Point of diversion	CDP I			CDP II			CDP III		
		Water available providing suggested stream-flows	Water diverted		Water available providing suggested stream-flows	Water diverted		Water available providing suggested stream-flows	Water diverted	
			High use estimate	Medium use estimate[1]		High use estimate	Medium use estimate[1]		High use estimate	Medium use estimate[1]
Yellowtail and Boysen Reservoir	At Hardin and Bighorn River	—	—	—	353,000	182,000	77,000	353,000	940,590	304,200
Yellowtail and Boysen Reservoir	Yellowstone River at Armells Cr.	—	—	—	[2]292,000	178,500	75,000	—	—	—
New Tongue Reservoir[3]	Tongue River at reservoir	63,000	58,000	36,100	—	—	—	—	—	—
Moorhead Reservoir[3]	Powder River at reservoir	77,000	23,000	14,400	—	—	—	—	—	—
Pumpkin Reservoir[3]	Powder River at reservoir	—	—	—	32,000	30,000	9,500	—	—	—

[1] Based on supplying a 250,000,000 cubic feet/day gasification plant with 9,500 acre-feet/year and supply a 1,000-megawatt generating plant with 12,000 acre-feet/year.

[2] Amount available is 474,000 acre-feet minus the 182,000 acre-feet diverted from the Bighorn River at Hardin. If medium use estimate is used 397,000 acre-feet of water would be available for other uses.

[3] Proposed.

Upper Missouri River Basin
Water Availability and Depletions

	Average year (acre-feet)	Critical year (acre-feet)
Historic flow[1]	28,321,000	–
Depletions for past use[2]	6,500,000	–
Water supply available after 1970	[3] 21,821,000	[3] 14,200,000
Indian requirements in Montana and Wyoming[4]	2,637,000	2,637,000
Committed to authorized Bureau of Reclamation projects[5]	1,293,000	1,293,000
Remaining water supplies subject to Indian claims[6]	17,891,000	10,270,000
Suggested water quality control required on main stem[7]	4,300,000	4,300,000
Available for additional development by Indians and non-Indians[8]	13,591,000	5,970,000

[1] Historic flow. This figure of 28,321,000 is an estimated value of long-time (1898-1972) average annual flow at Sioux City, Iowa, prior to any water development in the basin above Sioux City. It was derived from streamflow records adjusted for known and reported developments throughout the upper basin and the measured and estimated depletions associated with those developments.

[2] Depletions for past uses of water above Sioux City. The figure 6,500,000 is a composite of water depletions for all projects in operation in year 1970. Estimates include irrigation, imports, exports, land treatment measures, stockponds, rural domestic uses, evaporation from major impoundments, minerals and mining, industrial, and municipal uses. It represents water currently consumed and no longer available to meet additional future needs.

[3] Water supply available after 1970 is a measure of the expected average annual water production over the 1898-1972 period repeated, but with current uses accounted for. It is equal to the historic flow less all depletions for 1970 level of development.

[4] Indian requirements in Montana and Wyoming as compiled from inventories of land and water by consulting engineering firms under contract. Refinement in these preliminary numbers will evolve as studies continue. It should be noted that Indian water requirements do not necessarily define Indian water rights.

[5] Congress has authorized six units to be constructed by Bureau of Reclamation in the basin under the Pick-Sloan Missouri Basin Program. They are in the construction or preconstruction stage. The projects, authority, and expected depletions are:

Unit	Acreage	Depletion (acre-feet)[c]
Garrison Diversion Unit	[a]250,000	866,000
Oahe Unit	[a]190,000	303,200
O'Neill Unit	77,000	123,800
North Loup	53,000	99,900
Midstate	140,000	250,000
Narrows	[b]166,400	85,100

[a] Authorization also includes minor water usage for municipalities, FWL replacements and enhancements, recreation, and industry.

[b] Supplemental water supplies for lands currently without full supply.

[c] Depletion above Sioux City for authorized projects total 1,293,000 acre-feet from Garrison, Oahe, and O'Neill Units.

[6] Remaining water supplies subject to Indian claims. These figures are the residual flows after subtracting projected Indian claims in Montana-Wyoming and committed waters of authorized Bureau of Reclamation units from the water supply available as of 1970 level of

development. It represents water available for further development in the Dakotas and is subject to the undetermined permanent rights of Indians in the Dakotas for which land and water inventories have not begun.

[7] The value 4,300,000 acre-feet is the annual equivalent of 6,000 cubic feet/second currently thought to be the flow between and from main stem reservoirs required for recreation, flow maintenance, public health, and water quality control.

[8] These figures represent average and critical year water quantities available for future development in the Dakotas if water quality control flow requirements are maintained, and the demands listed in 4 and 5 are met.

[9] This value is an estimate which was derived from a recent operation study of the main stem reservoirs at 1970 development level. That study determined that water quality control could be maintained and also allow 9,900,000 acre-feet annually as the additional tolerable depletions which the system storage could accommodate. The number 14,200,000 is the sum of 9,900,000 and 4,300,000.

Through the construction of major reservoirs on the Yellowstone River and its tributaries, possibly 2,000,000 acre-feet of this water could be stored and made available for use in the Yellowstone Basin. Any depletion of water in the Yellowstone Basin would, of course, not be available for use downstream and would have an effect on the navigation season and on main stem hydropower generation. The environmental impact of such storage reservoirs was not assessed. It is clear, however, that any storage reservoirs built on the Yellowstone or its tributaries would have significant adverse effects and would be vigorously opposed by local and national organizations.

The Bighorn River is subject to provisions of the Yellowstone River Compact which allocates 80 percent of the natural flows, after recognizing rights existing prior to 1951, to Wyoming and 20 percent to Montana. In developing the suggested streamflows, the Water Work Group was not constrained to compact rights and requirements or Indian rights and potential uses. With the exception of the Bighorn River, the compact rights were not violated by this projection.

The MRBC[11] which is responsible for comprehensive water resources planning in the Missouri River Basin has FY75 funds to initiate a level B study of the Yellowstone River Basin and adjacent coal fields in Montana, Wyoming, and North Dakota.

b. *Western Dakota Tributaries.* The western Dakota tributaries, even with new storage, can provide only minimal amounts of water when compared to the Yellowstone Basin or the main stem Missouri River. Table IV-13 lists the potential reservoir sites on these tributaries and the amounts of water that could be made available from them. It should be noted that none of these reservoirs were used in the CDP. The inundated acreages required for storage reservoirs are very high compared to the amount of water that would be available on an annual basis. Although the environmental impact of building these reservoirs is unknown in detail, their construction is believed to be one of the least acceptable water supply alternatives that could be considered.

c. *Main Stem Missouri River.* Unlike the Yellowstone Basin, the Missouri River main stem has an abundance of stored water, some of which may be made available for coal development purposes. Three large reservoirs, Fort Peck, Sakakawea, and Oahe have a total storage capacity of 68,607,000 acre-feet (table IV-14).

The average annual flow at Oahe, which is below Fort Peck and Sakakawea, is 16,525,000 acre-feet. Of this amount, at least 3 million acre-feet could be made available for coal development without competing with existing or anticipated uses. Diversions of water from these reservoirs in the amounts studied would have relatively little impact on the existing aquatic habitat when compared to diversions in the Yellowstone Basin.

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[11] The Missouri River Basin Commission, under Section 201(b) of Public Law 89-80 is assigned the responsibility "to be the principal agency for planning the development of water and related land resources . . . ."

Table IV-17. - *Water available from Western Dakota tributaries*

River basin	Reservoir site	Total storage capacity (acre-feet)	Water available providing suggested instream flows[1] (acre-feet per year)
Little Missouri	Marmarth	508,000	26,000
	Medora	772,000	54,000
	Wagon Creek	230,000	14,000
	Beaver	59,000	2,000
	Bill Iron	45,000	3,000
Knife	[illegible]	305,000	17,000
Heart	-	-	Negligible
Cannonball	Mott	230,000	13,000
	Thunderhawk	216,000	13,000
	Cannonball	172,000	22,000
Moreau	Bixby	253,000	23,000

[1] Diversion from reservoir in all cases.

Table IV-18. - *Main stem Missouri River storage capacity at selected sites*

Dam	Reservoir	State	Capacity in acre-feet		Average annual flow (acre-feet)
			Total	Multiuse	
Ft. Peck	Ft. Peck	Montana	19,900,000	10,700,000	6,838,000
Garrison	Lake Sakakawea	North Dakota	24,200,000	13,400,000	16,972,000
Oahe	Lake Oahe	South Dakota	23,500,000	13,700,000	18,325,000

Figure IV-8 shows the amount of water that would be diverted from Lake Sakakawea in the year 2000 to supply the various CGP's.

4. *Deep Ground Water*. Recent study has indicated a potential for development of large supplies of ground water from the Madison Group and associated aquifers. These rocks underlie the entire Powder River Basin of Montana and Wyoming and are exposed on the flanks of the surrounding mountains. The aquifer rocks thicken toward the north and are deeply buried in the western and central parts of the basin.

The Madison and underlying carbonates contain water of moderate to good quality that is suitable for most industrial use with a minimum of treatment. Along the flanks of the Black Hills the water contains less than 1,000 milligrams/liter dissolved solids. Under much of the remaining part of the Powder River Basin, water in the deep aquifers has less than 3,000 milligrams/liter dissolved solids. Because of the cost of drilling deep wells, excessive pump lifts in large parts of the area, and the high percentage of sodium in the water in the center and northern portion of the basin, use of water from this source for irrigation is questionable. Although the water in general does not meet USPHS standards for use on interstate carriers, it is used for municipal water supplies for Newcastle, Osage, Upton, and Midwest, Wyoming.

Major ground-water development from the Madison Group, should it occur, would to a considerable extent consist of mining a resource because use may exceed recharge. If wells are put down near the center of the basin, where most of the strippable coal occurs, major

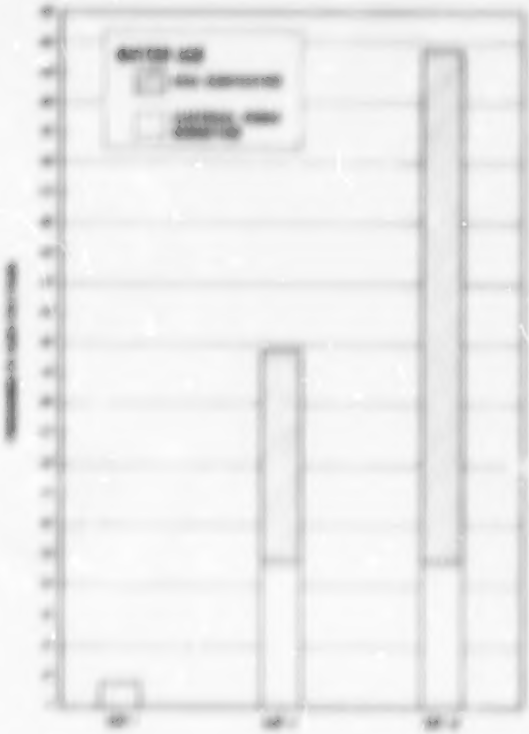

Figure IV-8. Water diverted from Lake Sakakawea for coal conversion facilities in North Dakota, Year 2000.

water development will probably not have any significant effect on recharge areas for many years. As mining of the water from the Madison occurs, the artesian head will decline, pump lifts will continue to increase, and the cone of influence of the well field will enlarge. In the Midwest, Wyoming area major water development from the Madison has been underway since 1917 when the Eadale well (T. 40 N., R. 81 W., sec. 14), yielding 4,000 gallons/minute, was completed as a water well. A total of 18 wells have been drilled in this area to supply water for the oil industry. Yields of wells in this area initially ranged from 400 to more than 3,000 gallons/minute. Available data show seven wells averaging 2,000 gallons/minute. Since 1917, the cone of influence of this well field has expanded under some six townships but has not reached the zone of recharge. The maximum decline in artesian pressure is about 200 feet.

A word of caution is necessary with respect to this source of water for coal conversion use. Substantial study should be undertaken prior to and during development to assess the effects that mining of water from the Madison aquifer may have on water supplies in the recharge area. Monitoring of declines in artesian pressure and spread of cones of influence of well fields must be maintained to prevent damage to prior water users. The aquifer system at present has such minimal use that much potential recharge is rejected but, as use increases, if major well fields are located too close to zones of recharge, flow of springs from the Madison and streams crossing this sequence of rocks may decrease.

6.0 Water Costs — Surface Water. The main variables affecting the cost of surface water are: (1) whether water can be taken without constructing a new reservoir (either from an existing reservoir or a diversion without storage), (2) the distance the water must be conveyed by aqueduct, (3) the amount of pumping required, and (4) the total amount of water moved through the pipeline since economies of scale may result in lower cost for larger aqueducts.

On the average, surface water for the North Dakota plant sites will be less expensive than surface water supplied to the Montana or Wyoming sites (Table IV-19). Since Lake Sakakawea is an existing water source, new impoundments are not necessary. Less pumping will be required due to the North Dakota terrain and the shorter distance from the lakes to the coal development sites.

Most of the North Dakota plant sites in either CDP II or CDP III are clustered together. Thus, capital costs or pipeline mileage increases very little. In Montana and Wyoming, the additional plant sites in CDP III are much farther away from possible diversions and may require more pumping. Consequently, capital and operating costs are significantly greater.

All costs of delivery systems and potential storage reservoirs were estimated on a January 1977 price base. The price base has steadily risen since estimating the costs, now almost 3 years old. The composite index of the general cost trend compiled quarterly by the Bureau of

Table IV-19.—*Water supply systems costs by CDP*[1]

	Water supplied, thousands of acre-feet (high water use estimate)	Total[1] capital costs, $ millions	Range of cost, dollars per acre-foot	Average costs, dollars per acre-foot
CDP I (Mont./Wyo.)	158	50	63-115	82
(N. Dak.)	89	7	38	38
CDP II (Mont./Wyo.)	423	503	47-310	147
(N. Dak.)	420	286	35-222	90
CDP III (Mont./Wyo.)	855	1,105	47-378	147
(N. Dak.)	738	444	40-199	77

[1] All cost data for choice No. 1 for each CDP as analyzed by Water Work Group.

Reclamation indicates a marked upward cost trend as follows:

1967	January 1973	January 1974	October 1974
1.00	1.41	1.52	1.78

Table IV-20 shows the costs of supplying water to the various powerplants and gasification plants in the three CDP's. The two choices shown are based on alternative aqueduct systems as described in the Water Work Group Report.

b. *Ground Water.*—The supply systems developed for each CDP consider only surface water as a possible water source; however, ground water has been discussed as a possible alternative. There are five variables which affect the cost of ground water from the Madison Group: (1) the depth of the aquifer, (2) the depth below the surface to which the water will rise under artesian pressure, (3) feasible withdrawal rates, (4) the cost of treatment, and (5) cost of transporting water to point of use. The nature of solids dissolved in the Madison aquifer water at locations near potential coal development sites makes it generally unsuitable for direct use in coal conversion facilities. However, with treatment the water would be considered a high-quality water supply probably exceeding the quality of most NGP surface water supplies.

Recent studies indicate that within the Montana and Wyoming portions of the study area where the ground water may be available, it would cost an average of $50 per acre-foot to construct the wells and pump the water to the surface. In comparing the cost of ground water to the cost of surface water in Montana and Wyoming, disregarding treatment costs only those plants within 30 to 40 miles of the point of diversion could obtain surface water at less cost than deep ground water.

Cost figures for ground-water supplies from the Madison aquifers are first approximations based generally on favorable assumptions of permeability and well yields. These costs are shown on table IV-21. They are not in the same order of precision as cost estimates of alternative surface water supplies. Costs for ground water may be higher or lower than indicated.

A comparison of surface water costs to ground-water costs are shown in table IV-22 for three selected powerplant sites. Similar relative costs would be found throughout the Powder River Basin.

c. *Effect of Water Cost on Development.*—Is it possible that the projected cost of water will be sufficiently high to affect the extent of coal development? To examine this question, the water costs were compared to the total value of gas produced. For the most expensive water use projected that is a plant using 30,000 acre-feet per year and assuming a cost of $350

Table IV-20.—*Summary of per acre-foot water costs by CDP*

Plant[1] No.	Quantity of water delivered, acre-feet/year (high water use estimate)	CDP I choices		CDP II choices		CDP III choices	
		1	2	1	2	1	2
P-1	23,000	$115	$325	$230	$ 89	$189	$234
P-2	19,500	63	193	144	183	146	143
P-3	19,500	74	209	165	162	168	127
P-4	19,300	48	257	167	121	179	97
P-5	19,500	80	296	80	296	80	80
P-6	23,000	38	38	89	54	64	26
P-7	23,000			222	95	199	192
P-8	23,000			175	124	152	144
P-9	23,000			102	152	95	173
P-10	23,000			140	104	116	78
P-11	23,000			198	276	182	184
G-1	30,000			176	275	378	203
G-2	30,000			310	133	268	328
G-3	30,000			210	66	238	290
G-4	30,000			118	199	224	274
G-5	30,000			92	268	206	253
G-6	30,000			124	126	206	253
G-7	30,000			74	70	195	277
G-8	30,000			47	43	189	271
G-9	30,000			151	134	161	243
G-10	30,000			50	52	133	152
G-11	30,000			50	52	133	152
G-12	30,000			50	52	92	298
G-13	30,000			53	75	47	84
G-14	30,000			47	88	47	84
G-15	30,000			35	28	47	84
G-16	30,000			35	26	47	84
G-17	30,000					118	88
G-18	30,000					97	68
G-19	30,000					76	47
G-20	30,000					76	47
G-21	30,000					76	47
G-22	30,000					105	76
G-23	30,000					154	95
G-24	30,000					154	95
G-25	30,000					109	133
G-26	30,000					49	76
G-27	30,000					49	76
G-28	30,000					49	76
G-29	30,000					49	76
G-30	30,000					49	76

Table IV-30.—*Summary of per acre-foot water costs by CDP*—Continued

Plant[1] No.	Quantity of water delivered, acre-feet/year (high water use estimate)	CDP I choices		CDP II choices		CDP III choices	
		1	2	1	2	1	2
G-31	30,000					49	76
G-32	30,000					49	76
G-33	30,000					49	47
G-34	30,000					49	47
G-35	30,000					40	66
G-36	30,000					40	66
G-37	30,000					51	49
G-38	30,000					54	29
G-39	30,000					80	32
G-40	30,000					80	32
G-41	30,000					80	32
G-42	30,000					135	128

[1] P denotes powerplants and G denotes gasification plants. Numbers correspond to the facilities shown on plate B-4 for CDP I, plate B-5 for CDP II, and plate B-6 for CDP III. Does not include 6,613 megawatts of coal-fired generating capacity in the 63-county area listed on table III-10.

per acre-foot and a selling price of $1 per thousand standard cubic feet, the annual water costs were 12.5 percent of the gross revenues. This analysis indicates that water costs could affect the level of water use and probably plant siting as well.

4-10. *Issues Which May Influence Water Cost, Availability, or Use*.—a. *Agricultural and Industrial Competition for Water*.—Energy companies have purchased partial water rights, options on water rights, and sometimes an entire ranch or farm in their effort to meet projected water needs. (This activity has occurred even where other water exists in storage and where agricultural water rights may not be convertible to year-round industrial use.) When energy companies purchase water rights which have previously been exercised for irrigation, they are reducing potential agricultural production even though they must exercise their rights so as not to injure other water users. This competition exists because of the limitations of present supply systems. As previously discussed (sec. 4-8), there may nevertheless be enough total water flowing through the region to satisfy the coal development hypothesized for any of the profiles as well as supply an increasing amount of agricultural use by year 2000. The principal conditions are (1) that in the Yellowstone Basin new storage facilities and possible aqueduct systems will have to be constructed and (2) specific areas may become water short depending on local conditions.

In addition to the future needs for water by agriculture, industry, and municipalities, the States have important aquatic and riparian habitats. If the existing aquatic systems are to be preserved, the amount of water available for other uses will be significantly reduced or the points of available water supply from the Yellowstone and other tributaries will be shifted to downstream locations. The environmental requirement to maintain certain minimum streamflows has varying legal standing in the NGP. Reservation of certain flows for fish and wildlife is now possible under the new water code in Montana. Such constraints complicate the issue of water planning throughout the region. The suggested

TABLE IV-21.--Estimates of cost of wells, pumps, and related facilities to supply water for selected hypothetical power and gasification plants

Site	Annual water requirement acre-feet	Static water level	Number of wells	Well costs	Number of pumps	Pump costs	Cost of collection and storage	Total capital costs	Capital recovery factor at 11.4 percent	Cost of pumping	Maintenance annual	Total annual costs	Cost per acre-foot
Powerplant No. 1	22,000	150 feet below land surface	16 wells 11,000-foot ave. depth	[illegible]	16	$640,000	[illegible]	[illegible]	[illegible]	$270,000	$ 60,000	[illegible]	[illegible]
Powerplant No. 2	19,500	80 feet above land surface	9 wells 10,000-foot ave. depth	5,400,000	9	180,000	1,000,000	6,580,000	750,000	95,000	36,000	877,000	45
Powerplant No. 3	19,500	140 feet above land surface	9 wells 10,500-foot ave. depth	5,670,000	9	135,000	1,000,000	6,805,000	776,000	59,000	27,000	862,000	44
Powerplant No. 4	19,500	500 feet above land surface	9 wells 9,000-foot ave. depth	4,060,000	Wells will flow naturally--No pumps		1,300,000	5,360,000	609,000	--	1,000	610,000	31
Gasification Plant No. 1	30,000	400 feet below land surface	12 wells 12,500-foot ave. depth	9,000,000	12	720,000	1,000,000	10,720,000	1,220,000	410,000	144,000	1,774,000	59
Gasification Plant No. 2	30,000	300 feet below land surface	12 wells 11,500-foot ave. depth	8,280,000	12	720,000	1,000,000	10,000,000	1,140,000	[illegible]	144,000	1,654,000	55
Gasification Plant No. 3	30,000	GROUND-WATER CONDITIONS AT THIS SITE ARE TOO UNCERTAIN TO ESTIMATE											
Gasification Plant No. 4	30,000	250 feet above land surface	12 wells 10,000-foot ave. depth	7,200,000	12	125,000	1,000,000	8,325,000	950,000	62,000	24,000	1,036,000	34
Gasification Plant No. 5	30,000	150 feet below land surface	12 wells 10,500-foot ave. depth	7,260,000	12	300,000	1,000,000	8,560,000	977,000	225,000	72,000	1,274,000	42
Gasification Plant No. 6	30,000	500 feet above land surface	12 wells 8,000-foot ave. depth	5,760,000	Wells will flow naturally--No pumps		1,000,000	6,760,000	770,000	--	1,000	771,000	26
Gasification Plant No. 7	30,000	200 feet above land surface	12 wells 8,500-foot ave. depth	6,120,000	12	100,000	1,000,000	7,220,000	824,000	40,000	20,000	884,000	29
Gasification Plant No. 8	30,000	500 feet above land surface	12 wells 8,500-foot ave. depth	6,120,000	Wells will flow naturally--No pumps		1,000,000	7,120,000	812,000	--	1,000	813,000	27
Gasification Plant No. 9	32,000	450 feet above land surface	12 wells 9,000-foot ave. depth	6,480,000	Wells will flow naturally--No pumps		1,000,000	7,480,000	854,000	--	1,000	855,000	27

Table IV-23.—*Comparison of CDP II water costs*[1]

Surface[2] water source	Surface[3] water amount, acre-ft	Surface[4] water unit cost, $	Surface water annual cost, $	Power-plant No.	Ground-water[5] annual cost, $
Moorhead Reservoir	12,000	89	1,070,000	1	759,000
Bighorn River	12,000	144	1,730,000	2	794,000
Yellowstone River	12,000	162	1,940,000	3	812,000

[1] Assumes 1,000-megawatt powerplant—77 percent capacity factor.

[2] From Water Work Group draft report.

[3] Assumes 12,000 acre-feet/year for 1,000-megawatt plant when surface water is used, ground-water plant treating water will use somewhat less—9,000 to 10,000 acre-feet/year (no terminal reservoir loss).

[4] From Water Work Group draft report—lowest price of choices offered.

[5] Assumes pumping cost of $50 per acre-foot. Assumes lime softener treatment ($75 per gallon/minute capacity + $0.0568/1,000 gallons), polymer addition ($0.117/1,000 gallons x cycles of use permitted), and sulfuric acid treatment (0.03 mil/kilowatthour, 38 percent efficiency of plant) (fixed charge rates of $0.15/year). Based on measured concentration of selected elements such as silica, calcium, and magnesium at three selected wells.

instream needs were largely but not entirely accommodated in the water supply studies.

Even though sufficient water may be available to meet both future agricultural and industrial demands, the price of water will affect its uses. Existing sources, such as those whereby irrigation water is converted to industrial use, can supply water at costs must less than the expected costs from new supply systems. There is an incentive for industry to buy the less expensive wat.r, which may reduce some agricultural activity. Industrial water demand patterns are markedly different from the spring-summer oriented demand patterns of agricultural users. These differences coupled with the fact that water diverted for industrial use may be completely consumed, whereas agricultural users characteristically return water to surface supplies or recharge aquifers, complicate planning for water use, particularly the conversion of agricultural water use rights to industrial uses.

b. *Indian Water Rights*.—The resolution of Indian water rights may have significant impact upon NGP water availability for all water uses. It is difficult at this time to predict the outcome of this issue, nor its effect. First, the priority of Indian water rights is contested in the States and among some non-Indian water users. Interpretation of priority dwells upon such distinctions as the time of Indian settlement and the date of reservation establishment. Further, the quantity of water reserved is questioned by many, particularly the States. Most Indians claim it is all water flowing on, by, or through the reservation. A position on this problem is contained in the separately bound report "Declaration of Indian Rights to the Natural Resources in the Northern Great Plains," prepared by member tribes of the Native American Natural Resources Development Federation of the Northern Great Plains.

c. *Article X of the Yellowstone River Compact*.—According to Article X of the Yellowstone Compact, the transbasin diversion of water from the Yellowstone Drainage Basin can occur only with the concurrence of the signatory States—Wyoming, Montana, and North Dakota. The provisions of this article were not met on the Bighorn River at the CDP III level of development in that two plants sited outside basin boundaries, both south of Gillette, Wyoming, were supplied with Yellowstone Basin water.

If coal development occurs south of Gillette and if the signatory States do not concur with transbasin diversion, water must be provided from some source other than that proposed in the profile analyses.

The principal alternative source for surface water would be Oahe Reservoir. The Green River may also be considered as a water source. Water from Oahe will be more expensive than water from within the basin (table IV-23) but its use does not violate the Compact. Water from the Green River is the most expensive option and being a tributary of the Colorado River diversion of water from its basin will contribute to the salinity and related problems of the Lower Colorado Basin.

Another alternative water source is ground water. Assuming that a sufficient quantity of ground water is available in the Gillette area, its cost is currently estimated to be less than that supplied by any surface water source studied. But it must be remembered that many unknowns relating to recharge rates and impacts of large-scale use of the ground water, especially the deep ground water in the Madison sequence, exist and that more information is required before these waters can be assumed available.

Table IV-23.—*Cost of providing water to selected plant sites by alternative conveyance systems*

Source of supply	Average cost per acre-foot, dollars
Miles City to south of Gillette aqueduct	232
Bighorn Lake to south of Gillette	286
Oahe to south of Gillette aqueduct	359
Ground water from Madison formation	[1]55

[1] Cost includes water treatment.

4-11. *Impacts of Water Development*—a. *Water Quality*.—

(1) *Present conditions*. The headwaters of most streams in the study area, particularly those originating from snowmelt in the mountains of Wyoming and Montana, have excellent water quality. The available data indicate degradation of the chemical and physical quality as streams progress downward. The degradation results from natural hydrogeologic conditions and man's uses.

Table IV-24 summarizes water quality for several rivers in the NGP. (These data are supplemented by a more extensive summary and discussion in the Water Work Group's Water Quality Subgroup Report.) As can be seen from the table, there are many parameters used in characterizing water quality; generally they are concentrations of various impurities. The importance of these various parameters depends on the use that is to be made of the water.

The U.S. Public Health Service recommends that drinking water should generally have a total concentration of dissolved salts less than 500 milligrams/liter have a low concentration of several specific toxic or pathogenic substances. The latter include a number of the trace elements listed in table IV-24. The requirements for water that are to be used for industrial purposes vary greatly, depending on the particular use intended. In general, however, industrial water should be as low as possible in TDS and hardness; for particular uses, low concentrations of certain trace elements are also important. The requirements for the use of water for irrigation are crop dependent but generally involve low concentrations of TDS and certain trace elements toxic to plants, such as some of those listed in table IV-24. As TDS concentrations progress from 250 to 1,000 milligrams/liter, water becomes progressively less useful for irrigation. In many situations the most exacting requirements on water quality are those for the maintenance of aquatic life. Different species have rather widely different requirements with regard to temperature and DO (dissolved oxygen), but each species will usually tolerate only a narrow range for

Table IV-24.—*Water quality summary*[1]

[illegible]

Legend

DO - Dissolved Oxygen
BOD - Biochemical Oxygen Demand
pH - [illegible]
Flow - [illegible]
TDS - Total Dissolved Solids

SS - Suspended Solids
NO_3 as N - Total Nitrate as Nitrogen
NH_3 - Ammonia
PO_4 as P - Total Phosphate as Phosphorus
Pb - Lead

Cu - Copper
Hg - Mercury
F - Fluoride
Se - Selenium
Al - Aluminum

B - Boron
Zn - Zinc
mg/l - Milligrams per liter
µg/l - Micrograms per liter
-- No Data Available

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[1] Period of record is approximately 1965-1973. For specific data see Water Quality Subgroup Report.

Source: EPA Data STORET (Storage and Retrieval System). Federal and State measurements. Also, Water Quality Subgroup Report.

these parameters. Concentrations of TDS and toxic trace chemicals are also important, each species having particular requirements.

Water quality standards have been established in the States for particular stream reaches, in order to allow the water to be put to particular so-called beneficial uses. Significant deviations of water quality parameters away from the values set by these standards can be detrimental to these beneficial uses. Particularly sensitive to such variations is the use of water to maintain aquatic life. The disappearance of many species from a stream can be expected if water quality parameters are changed drastically. Analysis of the effects of changes in water quality must be specific to each particular reach of stream and to the beneficial uses to which the water is to be put, however, so it is not possible to make any further general statements.

Except in a few localized areas, water quality in the NGP remains satisfactory for irrigation, livestock watering, recreation, fish and wildlife, municipal, and industrial purposes. The few severe local problem areas are usually associated with high levels of activity: municipal or agricultural. Such problems usually occur in areas where the activity is on depleted or low-flowing streams, and the occurrences are on a seasonal rather than year-around basis.

Natural degradation in stream quality can most easily be described in terms of changes in such physical and chemical parameters as temperature, sediment, and dissolved solids. Temperatures increase as a stream proceeds downstream and its water receives increased exposure to solar radiation and its absorbent heat. Likewise, sediment and dissolved solids generally increase as streams proceed toward their mouths. Erosion and subsequent siltation are significant problems in the NGP area.

These natural changes affect the aquatic ecosystem. A cold water ecosystem, commonly referred to as a trout stream, exists in the upper reaches of most NGP streams. The lower reaches, because of higher temperatures, more sediment, and elevated levels of dissolved materials generally have a warmer water ecosystem, and in some cases are characterized by more pollution-tolerant species, such as catfish and goldeye fish. This ecosystem is commonly more complex and varied than is the colder water ecosystem.

Agricultural and urban activities also affect water quality in the NGP. Agricultural influences on water quality consist primarily of depletion of streamflows, return flows of irrigation water, crop and pasture land erosion, and feedlot wastes. Sediment, nutrients, and dissolved solids in irrigation return flows to streams differ in concentrations, depending on farm and water management practices. Average (arithmetic) TDS concentrations range from 844 to over 2,500 milligrams/liter in the Powder, Heart, Knife, Cannonball, Belle Fourche, and Cheyenne Rivers (table IV-24). Concentrations within this range can be detrimental to crops, aquatic life, public use, and industrial use in cooling, boiler water, and food processing.

Suspended sediment concentrations and loads at a given site vary widely throughout the year. The sediment load is normally light in the upper reaches of the major streams but increases in the middle and lower reaches. While erosion is a significant natural pollution problem, disruption of the land surface by tilling of soil, grazing, construction activities, organics, and other mining can and do significantly increase erosion rates.

Washout of feedlot wastes contributes bacteria and organic nutrients to the stream, which result in depletion of dissolved oxygen and increased bacteria and algae concentrations. These pollutants can cause changes in the types of aquatic organisms found in the stream and later its recreational and esthetic value.

Wastes generated from municipalities generally contain organics discharged from sewage treatment facilities and solids washed by runoff from streets and construction sites. These sources contribute suspended and dissolved solids and a variety of nutrients, such as nitrates and phosphates, to the receiving stream.

The average DO level for all stream locations sampled in the NGP area ranges from 8.5 to 12 milligrams/liter. However, a marked reduction in oxygen levels has been found during the summer months below certain municipal waste water outfalls and in some reaches with low flows resulting from diversions and natural conditions. A zero dissolved oxygen concentration has been recorded for the Heart River near Dickinson and, prior to construction of Garrison Dam, for the Missouri River at Bismarck.

Naturally occurring water temperatures in the high mountain streams differ significantly from the lower streams and reservoirs of the plains. Significant water depletions contribute to the increased temperatures because the lower volume is heated more quickly by solar radiation. The effect of diversions and return flows on stream temperatures is more noticeable in summer months when solar radiation and water demands for domestic uses, irrigation, and industry are high.

Data on existing concentrations of trace elements in the waters of the NGP are very limited. It is recognized that certain trace elements are essential to normal biological cycles; however, trace elements may also have harmful effects on crops, livestock, aquatic life, and humans. Activities that increase the concentration of dissolved solids also have the potential for increasing the concentration of trace elements. Review of the limited data available suggests that harmful concentrations of trace elements are generally absent in NGP streams. However, as the data in table IV-24 show, certain trace elements are sufficiently concentrated as to be potentially harmful.

The present emphasis on the Federal and State pollution control programs is to clean up localized effluent discharges generally referred to as point sources. Regulation of discharges of municipal, industrial, and feedlot wastes has improved overall water quality and will continue to be effective. The pollution problems caused by nonpoint sources of pollution such as land surface disruption, water withdrawal from streams, and contamination of ground water are not easily identified or abated and will require an extended effort to control their potential pollution effects.

(2) *Potential changes in water quality.*—Changes in water quality must be expected should additional coal development occur. The extent of such a change is a function of the method chosen to supply water to conversion facilities, the kind of industrial water use, the potential for discharge from mines, and the environmental standards imposed. Analysis of the CDP's indicates some changes in water quality on a gross, but not necessarily regional basis, regardless of the level of assumed coal development. The analytical tools used for the analysis lack the sensitivity needed to accurately predict the changes in water quality from a single coal mine or coal conversion plant. Therefore, local impacts on water quality that may result from individual and isolated discharges are not predicted.

Estimates based upon the CDP I development profile showed greater water quality impacts than did analysis of the other two CDP's. This is primarily because of the methods (reservoirs, diversions, and aqueducts) chosen to deliver water. Under CDP's II and III economies of scale and siting allowed less detrimental diversions to be employed. These water diversion schemes were not feasible under CDP I because the limited amount of water required would not justify their economic costs.

The predicted impacts of water diversions and use on water quality are also determined by assumptions about the quality of water diverted, the treatment or discharge techniques, and the quality of the discharge relative to the receiving streams. For example, if water diverted from one watershed is utilized in another and the discharge is of better quality than the water in the receiving stream, the water quality of that stream may be enhanced. That stream losing water will probably suffer a loss in water quality simply because its volume and therefore its dilution capability will be reduced.

(a) *Surface mining impacts.*—The

surface mining of coal is one of the major activities that can cause changes in water quality. Removal of water that infiltrates active mines may cause pollution if inadequately treated. Runoff from disturbed areas, if inadequately treated, will contain sediment, dissolved solids, trace elements, and possibly nutrients. Strip mining, which breaks up and exposes large amounts of earth material, increases the concentration of dissolved salts, nutrients, and trace elements in ground water, which then may flow into a nearby stream.

Recent sampling of shallow ground water at mines near Colstrip and Decker, Montana, have indicated the pollution potential. Data from the Colstrip area show relatively high concentrations of calcium, magnesium, sulfate, and TDS in waters which drain from spoil banks. In the same area concentrations of two trace elements in spoil bank waters (manganese and lead) were found to exceed the U. S. Public Health Service drinking water standards. The drainage from strip mining activity in the vicinity of Colstrip appears to contribute to significant increases in TDS in surface water (an increase from about 2,200 to 3,500 milligrams/liter). In the Decker area, the major chemical constituents in water draining into the mine are sodium, bicarbonate, and sulfate. Since the ground water in the area contains little, if any, sulfate a sizable amount must be leached as a result of the mining operations. The relatively strong mineralization of overburden, demonstrated by saline seeps in the area, is a major if not the primary cause for changes in the area's ground-water quality. Although no conclusive demonstration is available to indicate the direct effect of mining operations on surface water quality, these shallow ground-water studies indicate to some extent the potential for surface water quality degradation.

An increase in the concentration of dissolved solids, including trace elements and nutrients in ground water, will in many cases is transported to a stream or river by underground flow. Mines close to streams have the most potential for rapid degradation of surface water quality.

The persistent nature of this type of pollution and the difficulty in abating it poses one of the most difficult environmental problems for mining operations. Further data collection and analysis are needed to better understand the potential for water quality problems resulting from mining and to evaluate schemes for minimizing water quality degradation.

(b) *Coal gasification and powerplant impacts.*—Coal conversion facilities also have the potential to cause water quality changes. These industrial plants will utilize water consumptively, reducing flows, and thereby reducing the river's ability to transport and/or dilute natural or man-induced inflows. Waste water containing elevated temperatures, dissolved solids, and trace elements from gasification and powerplants as well as certain organics from gasification plants could cause water quality degradation. These plants can be designed to use a minimum amount of water and have essentially no effluent. Most "no discharge" plants at present utilize large solar evaporation ponds for ultimate waste disposal. The impact of these ponds on ground water, wildlife, and water fowl are very site oriented. Such operations are generally considered preferable to operations that discharge into a nearby stream, provided no substantial seepage occurs and the solids resulting from the evaporative process are properly disposed of.

Water quality changes that have been quantitatively evaluated by the NGPRP to date have assumed that the industrial plants will use more water than they will consume and therefore will discharge water to local streams. Should plants be built using smaller quantities of water and having no discharges, overall regional water quality changes resulting from coal conversion would be less because less water would be diverted from streams like the Bighorn and Yellowstone, and no streams would receive contaminated effluents from conversion facilities.

One water quality parameter, TDS, can be sufficiently modeled so that rough estimates of the degree of water quality change can be made. The projections are based entirely on estimates of consumptive use of water by coal-energy conversion plants and do not include TDS increases caused by runoff from disturbed areas, leaching of mine spoils, or increase in agriculture or other water use. These other sources of TDS are not incorporated into the projections; however, they are known to have significant impacts on water quality. These projections are based on numerous assumptions and need refinement as more and better data are compiled.

Powerplants of 1,000-megawatt size were *assumed* by the Water Work Group, to have an annual discharge of 5,000 acre-feet, thereby concentrating the TDS by a factor[11] of 3.8 times the intake concentration. Discharges from gasification plants (250 million cubic feet/day) are assumed to range from 20,000 to 10,000 acre-feet annually. The concentration factor for gasification plants then has a range of 1.5 to 3.0. These numbers, along with estimates of existing TDS concentrations in rivers of the region, are used to make the TDS projections.

These projections indicate that the average annual concentration of TDS in the Missouri River at Bismarck, North Dakota, in year 2000, would increase for CDP III from 436 milligrams/liter to between 465 and 500[12] milligrams/liter or approximately 7 to 15 percent. For CDP II level of development, projected increases for the Missouri River at Bismarck are between 445 milligrams/liter, a 2 percent increase, and 470 milligrams/liter, an 8 percent increase. The large volume of water which flows in the Missouri River below Garrison Dam—approximately 15 to 16 million acre-feet/year—has a tremendous dilution capability which is the principal reason for the small increases in these TDS projections.

Table IV-25 shows the results of TDS projections for some other potentially impacted rivers of the region. In the case of the Powder and Knife Rivers a decrease in the TDS concentration is indicated as being possible. This finding results from using a water supply source with a relatively low TDS concentration (Bighorn River and Lake Sakakawea) and discharging into water with a relatively high TDS concentration. The low TDS concentrating factor of 1.5 for gasification plants is another major reason for the indication of possible improvement in TDS concentration in the Powder and Knife Rivers.

The TDS projections indicate that of the rivers analyzed the Tongue River has the greatest potential for being impacted by discharges from coal conversion facilities. Projected increases in TDS range from 25 to 41 percent for CDP II and 36 to 62 percent for CDP III. This potential TDS increase is due in part to the relatively low dilution capacity (flow) in the Tongue River compared with the Yellowstone and Missouri Rivers. Also, the Tongue River historically has low TDS concentrations compared to the other Yellowstone and Missouri River tributaries analyzed, and therefore discharges with high TDS concentrations will result in a greater change in the Tongue River than in the Powder, Knife, and Heart Rivers.

TDS projections for annual low-flow conditions show an even greater increase in TDS concentration. For example, under CDP III and flow conditions which occurred in 1966 the Tongue River at Miles City is projected to have an annual

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[11] $\frac{\text{Intake volume}}{\text{Effluent volume}} = \text{Concentration factor}$

[12] Includes the effects of a reduction in flow in the Missouri River at Bismarck resulting from development of the Garrison Irrigation Project.

Table IV-25.—*Projected annual average total dissolved solids concentrations resulting from assumed discharge from coal gasification and power generation plants*

River and location	Historical average concentration (mg/l)[1]	Range of TDS projections (mg/l)	
		CDP II	CDP III
Tongue River at Miles City, Montana	560	700-790	760-910
Powder River at Moorhead, Montana	1,552	1,410-1,590	1,380-1,770
Yellowstone River near Sidney, Montana	460	480-490	510-530
Knife River at Hazen, North Dakota	1,004	870-1,100	790-1,150
Heart River near Mandan, North Dakota	844	860-870	850-890
Missouri River at Bismarck, North Dakota	436	445-470	465-500

[1] Milligrams per liter

Note: These projections are based on numerous assumptions and need refinement as more and better data are compiled. Therefore, this table should be used only to make broad inferences about potential TDS concentrations.

TDS concentration from 880 to 1,120 milligrams/liter. For CDP II the projected TDS range is from 800 to 960 milligrams/liter. The average TDS concentration during 1966 was 645 milligrams/liter. For the once-in-10-year low-flow conditions, again 1966, the Yellowstone River at Sidney is projected to have TDS increases from 500 to 510 milligrams/liter for CDP II and from 540 to 570 milligrams/liter for CDP III. The average TDS concentration at Sidney during 1966 was 491 milligrams/liter. For more information on these projections, including monthly projections, the reader is referred to the report of the Water Work Group's Water Quality Subgroup report.

The importance to water users of these increases in TDS concentrations is dependent upon many factors which have not been adequately assessed to make any specific conclusions. Generally, TDS concentrations in excess of 1,000 milligrams/liter are considered to adversely affect many irrigated crops but actual limits range considerably, up or down, according to the particular crops grown, soil composition, drainage, and water management practices. The EPA has proposed a maximum acceptable TDS concentration for livestock drinking water of 3,000 milligrams/liter but higher concentrations are tolerated by livestock in the region. Generally, water is considered good for public drinking supplies if the TDS concentration does not exceed 500 milligrams/liter but many communities in the region utilize water with much higher TDS concentration.

The constituents of the TDS are important in considering their effects at higher concentrations. Certain constituents such as sodium and boron are harmful to crops, and others such as sulfates and chlorides are undesirable for public water supplies. Many of the trace elements can be toxic to aquatic life, livestock, and humans. The potential of certain dissolved constituents for causing water quality problems as a result of coal-energy development is unknown and additional data collection and study will be required. Initial work on the assessment of potential effects of increases in trace elements in the NGP is being conducted by EPA.

(c) *Sewage treatment impacts.*—An influx of people, necessary to support development, is also a potential cause of changes in water quality. Rapidly growing communities traditionally have the problem of inadequate sewage treatment facilities. There is normally a lag between the arrival of large numbers of people and the institutional and financial framework required to build additional treatment facilities. The associated problems of nutrification, DO depletion, and aquatic toxicity resulting from poorly treated sewage cause serious degradation of water quality. This potential water quality problem will be most serious for rapidly growing towns with moderate to large populations discharging their sewage effluents into seasonally low-flowing streams.

Discharges of treated domestic wastes can cause significant depletion of DO when the capacity of the stream to biologically assimilate the wastes is less than that discharged into the stream. DO analyses were made for Billings and Miles City, Montana, along the Yellowstone River and for Sheridan, Wyoming, along Goose Creek, a tributary of the Tongue River. These municipalities were chosen because of the availability of USGS stream data and because these sites represent a range of flow and population impacts which might result from coal-energy development. At all three locations, secondary treatment was assumed as defined by EPA.[11] Complete mixing of wastes in the stream was also assumed. It was found that during August low-flow conditions, an estimated population for Billings corresponding to CDP III would not cause a violation of the dissolved oxygen standard in the Yellowstone River. Similarly for Miles City no violation of the DO standard would be anticipated using the August instream flow requirement (suggested minimum flows used elsewhere in this report) as the low flow for that location. Sheridan, Wyoming, along a low-flowing stream, was shown to have a high potential for violating the DO standard depending upon the estimated influx of people into that city. A population in Sheridan of between 14,000 and 23,000 with secondary waste treatment is estimated to result in violation of the DO standard. (For a complete explanation of this analysis, see the Water Work Group's Water Quality Subgroup report.) Industry may purchase rights to use such effluents, thereby reducing the potential for polluting streams.

In general these DO analyses imply that with secondary waste treatment the Yellowstone and Missouri River main stems will not be significantly impacted with respect to DO as a result of current population influx estimates and the aqueduct diversions discussed earlier. Conversely, cities and towns discharging their effluent into creeks and low-flowing streams of the region can expect to go beyond secondary treatment of domestic wastes, or limit the discharge rate, if significant population growth is experienced in the area. These areas include such municipalities as Sheridan, Buffalo, Gillette, Dickinson, and potentially many others.

In this analysis of DO impacts, an important assumption should be reemphasized. The assumption is that secondary treatment as defined by EPA is assumed for all municipal waste discharges. Since the secondary treatment standard is required for all municipalities by July of 1977, this assumption is reasonable. But the realities of financing the upgrading of existing treatment facilities may cause a lag in implementation of this standard. This situation is especially true for small, rapidly growing communities which require substantial revenue to provide secondary treatment for future populations but lack the economic base upon which to generate the required dollars. The existence of such communities will most likely be fostered by rapid coal-energy development. If so, State and Federal governments must recognize this problem at an early stage and formulate plans to deal with the local needs. Otherwise, the pollution of streams and rivers will be more drastic than revealed by this report.

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[11] Federal Register, August 17, 1973, vol 38, No. 159, part II.

b. *Shallow Ground-water Impacts.*—In many areas of the NGP, shallow coalbeds serve as locally important aquifers which supply water for agriculture and domestic activities outside of the major drainage channels. Coal mining in the NGP thus will change, at least on a temporary basis, the local shallow ground-water system in many mined areas. The change will involve at least temporary declines in water tables and deterioration of ground-water quality.

The complexity and variability of the shallow aquifer system from one area to another makes it difficult to generalize about the impacts of exploration, extraction, and energy conversion phases of coal development on the ground-water resource. The following discussion, however, reviews briefly those impacts that have been observed in areas where mining is in progress. It must be emphasized that extrapolations of these data to areas that have not been investigated in detail must be used with caution. It is not possible to make specific conclusions about the regional impact of surface mining and energy development on the shallow ground-water system because of (1) the early stage of investigations and (2) the variabilities of the system at the mining tract scale.

Although ground-water flow patterns vary depending on local geologic structures, ground-water movement in shallow aquifers of the NGP is characteristically from recharge areas along the higher interstream divides toward discharge areas in the bottoms of the principal stream valleys. Existing and potential strip mines are located at all points within this generalized path of ground-water movement. Some mines are located in recharge areas, others at or near areas of ground-water discharge and many others are located at intermediate points along paths of ground-water flow.

(1) *Impacts on ground-water availability.*—In discharge areas, a mine acts much like a huge well into which water is discharged from those aquifers intersected by the trench, this may include coalbeds which are commonly water-bearing units. Since, in most circumstances, coalbeds directly overlie relatively impermeable strata, seepage up through the mine floor is not likely to occur and the intercepted water is all that is collected in the mine. The intercepted aquifers generally yield less than 100,000 gallons/day at individual mines, some of which may be used seasonally for mining operations. This volume will vary depending upon the aquifer(s) intersected and other local conditions.

An example of such variation is a mine near Decker, Montana, which yields an estimated 250,000 to 300,000 gallons/day, most of which is discharged to surface drainages. About 215,000 gallons/day of the Decker mine water is attributed to lateral seepage from the nearby Tongue River Reservoir.

Depending on local hydrologic conditions, mines located between recharge and discharge areas may also intercept significant quantities of ground water. Depending on the mining method chosen, mines located in areas of ground-water recharge may or may not reduce or eliminate supplies to the downdip portion of the aquifer.

Few generalizations can be made about the extent to which water levels in affected wells decline. Observations in the Gillette, Wyoming, area show that the principal shallow aquifers are discontinuous sandstone beds erratically distributed in the Wasatch and Fort Union formations. Comparatively few wells obtain water from the

Wyodak-Anderson coalbed. Water levels in wells less than a mile from active mines show no appreciable decline.

Conversely in the Decker, Montana, area water occurs in discontinuous sandstone beds in the Wasatch and Fort Union formations, but the principal aquifer is the D-1 coalbed. Over a period of 2 years water levels in research wells tapping this aquifer in the vicinity of the Decker mine (initiated in 1972 with an open cut about 12,000 feet long and about 100 feet deep) declined after 15 months of mining about 20 feet at a distance of about 0.5 to 0.75 mile from the mine. As mining continues, it is likely that a number of privately owned wells within several miles of the mine will be adversely affected by declining water levels. Hopefully, these impacts can be mitigated by drilling 100 to 200 feet deeper to underlying coal or sandstone beds where water supplies of equivalent or better quality and quantity can be developed.

Water level declines in the Gillette, Wyoming, and Decker, Montana, areas may reflect the range of conditions that can be expected in the NGP coal region. Lowering of pumps and deepening of wells will be necessary in some localities.

Depressed water tables can be expected to persist in the vicinity of each mine until operations are discontinued. If the surface of the rehabilitated terrain was not lowered appreciably by removal of the coal, water levels then should slowly recover to about the levels that existed prior to mining.

Very limited measurements are available regarding the porosity and permeability of mine spoils. Initially, at least, porosity and probably both vertical and horizontal permeability of the back-filled spoils will be greater than in the undisturbed overburden prior to mining. Compaction will gradually occur with time, especially after mining when water levels rise and the spoil becomes partially saturated.

After compaction, porosity and vertical permeability of the backfill will probably remain greater than that of the premine overburden. Depending on site specific conditions (nature of overburden materials, method of spoils handling, etc.), the horizontal permeability of the spoil may or may not equal or exceed that of the original undisturbed sediments.

Given general projections for postmining water table recovery and the likelihood that compacted spoils will have equivalent or increased porosity and permeability, it seems reasonable to conclude that in time ground water will be physically available again in areas of mining disturbances. A key question is "how much time?".

(2) *Impacts on ground-water quality.*—As discussed above, after an indeterminate period ground water will again be physically available in most areas where existing aquifers are disturbed by surface coal mining. Of critical concern is the general lack of information with which to predict whether the water will be of sufficient quality to be usable for domestic, livestock, and irrigation purposes.

Both laboratory and field measurements show that water percolating through spoils materials contains significantly higher concentrations of dissolved solids than water moving through undisturbed overburden and coal nearby. It is highly likely that most of the increased dissolved solids are derived from the more shaley material in the spoils. Before mining such material is relatively impermeable and, hence, the salts and other soluble components it contains have not been appreciably exposed to ground water.

As these "tight" units are broken and placed in spoil banks, the surface area exposed to water will be increased astronomically. The newly exposed soluble materials may then be leached by water moving either laterally or vertically or both.

Concentrations of dissolved solids should increase in the direction of flow through the spoil deposits and should depend in large part on the composition, rate of chemical weathering and permeability of the spoils, and on the rate of ground-water movement through these materials.

Major leachable ions include sodium, magnesium, calcium, sulphate, and carbonate. Limited sampling at Colstrip, Montana, generally shows higher concentrations of the above ions in water obtained from the spoils than in water from undisturbed aquifers. Concentrations of certain base metals also show marked increases in Colstrip spoil waters. The levels of arsenic, lead, manganese, and sulfate consistently exceed U.S. Public Health Service Drinking Water Standards. Such data have been collected for only a relatively short period of time at a small number of sites. Although comparisons with drinking water standards have been made, very little is known about the utility of spoil water for livestock and irrigation.

Following are comparisons from Van Voast (1973) of water samples from two wells in the Colstrip area, Montana. One well taps old spoil materials and the underlying Rosebud coalbed; the other taps an unmined coalbed. Parameters are in milligrams/liter.

	Water from old spoils and the Rosebud coalbed	Water from the unmined coalbed
Date of collection	9-25-73	9-25-73
Calcium (Ca)	467	53
Magnesium (Mg)	351	51
Sodium (Na)	114	190
Potassium (K)	9.0	8.1
Iron (Fe)	1.82	0.26
Manganese (Mn)	1.35	0.07
Silica (SiO_2)	16.0	14.3
Bicarbonate (HCO_3)	483	553
Carbonate (CO_3)	0	0
Hydroxide (OH)	0	0
Chloride (Cl)	15.9	4.1
Sulfate (SO_4)	2,418	284
Nitrate (NO_3)	15.5	1.1
Fluoride (F)	0.1	0.1
Calculated dissolved solids	3,892	1,159

Concentrations of dissolved solids in water moving through the spoils materials seemingly should decrease with time as the soluble ions are removed by leaching. Water from spoils 45 to 50 years old in the Colstrip area, however, is similar in dissolved solids content to water from much younger spoils in the same area. Apparently, no significant decrease in the rate of leaching of ions has occurred in that period of time. This may be due to the very low ground-water gradient at Colstrip (low velocity of ground-water flow) or it may indicate that such ground-water quality problems will persist for prolonged periods.

Further laboratory and field work is urgently needed to arrive at a "mass balance" for leachable solids and to predict "how long before degraded ground-water starts to significantly improve." Until these questions are answered and until the lateral and vertical extent of ground-water degradation can be predicted, essentially nothing can be concluded about the regional significance of ground-water quality problems.

One can conclude, however, that such problems are likely to be most severe if mines are located in major alluvial valley floors. According to a recent U.S. Geological Survey analysis[14] "a mine that penetrates the full thickness of alluvium in a stream valley to reach the underlying bedrock and coal probably will affect not only nearby wells in the bedrock but will decrease the amount of water in the alluvium and possibly degrade the quantity and quality of streamflow for considerable distance downstream."

Special precautions should also be taken if mining proceeds in areas of ground-water recharge. Otherwise, the quality of water will be affected in aquifers downdip from the mine spoils.

The costs of mitigating the shallow ground-water impacts are largely unquantified but include (1) tests and measurements of spoils properties, aquifer hydrology, and water quality; (2) lowering pumps in existing wells or deepening existing wells to replace interrupted water supplies and existing uses such as fisheries; (3) placement of saline spoil at levels above project elevation of the projected ground-water table; and (4) possibly the shaping of the land surface and establishing a plant cover that will minimize movement of water downward through the soil veneer into the underlying spoils materials.

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[14] Shallow ground water in selected areas in the Fort Union Coal Region, U.S. Geological Survey, open file report 74-48, 1974.

Even more difficult to quantify are the potential "costs" to fisheries, agriculture, and other surface water uses as degraded ground water enters surface drainages.

Total adverse impacts on ground-water quality and availability could prove small when examined on a regional basis. However, within many basins the impacts on existing and potential water uses may be monumental. If a rancher loses water for his cattle or can no longer irrigate his meadow, he surely will not be comforted by observations that the problem is of small regional significance.

c. *Impact of Water Development on Land Resources.*—The "suggested streamflow" establishes a criterion for estimating the impact of flow depletions on the aquatic ecosystem. All specific CDP water supply alternatives examined in this report met the "suggested streamflows" except the Hardin aqueduct diversion for CDP III development. Although meeting the NGPRP "suggested streamflow" requirement is not certain to maintain the existing aquatic life, not meeting them would generate a tremendous potential for inducing stress and therefore altering the type of aquatic ecosystem.

There are other basic environmental considerations that must be made in evaluating impact of water supply alternatives, particularly those utilizing aqueducts and reservoirs.

Most of the land disturbed during the construction of a buried pipeline aqueduct may be restored within a few years, although its value as wildlife habitat may be different than it originally was. A longer term loss of grazing and wildlife uses from aqueducts would result from placement of a roadway along the aqueduct route to facilitate maintenance of facilities. Crossing through streams would result in temporary degradation of downstream water quality and loss of habitat for some aquatic organisms. Open waterways would pose special problems in terms of disruption of travel routes, egression from concrete-lined canals, and a complex of other problems.

With reservoir construction, there is a direct irreplaceable loss of land due to permanent flooding. As an example, 156,000 acres of Missouri River bottom lands and adjacent uplands were lost when Lake Sakakawea was formed. Seasonal flooding of downstream riparian habitat, flushing of stream channels, water quality characteristics, and other parameters are modified downstream subsequent to impoundment. Some of these changes may be beneficial while others are generally detrimental to existing fish and wildlife resources.

Generally, aqueducts diverting water from an existing storage facility exert less severe impacts on terrestrial wildlife than do new impoundments. Impacts on aquatic resources are often dependent on the quantity of water left in the stream to meet instream flow requirements and maintain riparian habitat and water quality.

D. Air Resources

4-12. *Ambient Air Quality.*—The NGP region is relatively free of large-scale air pollution problems. Extremely clean air is a trademark. Visibilities of 50 miles or more are commonplace. "Big Sky" is more than the motto of a single State—it is a concept treasured by all people who live in the region and one quickly grasped by visitors. In this section the impacts of coal development on the air resources of the region are discussed and certain assessments are made.

Good dispersion conditions for stack gas plumes exist on a regional basis under normal conditions as a result of the frequency and intensity of air movement in the study area (fig. IV-9). Average annual wind speeds range from 8 to 14 miles per hour with Casper, Wyoming, in the highest part of the range (fig. IV-10). Winter chinook winds occurring near the eastern side of the Rocky Mountains may last for several days and reach 25 to 50 miles per hour.

The dispersive characteristics of a stack gas plume are also dependent upon the mixing

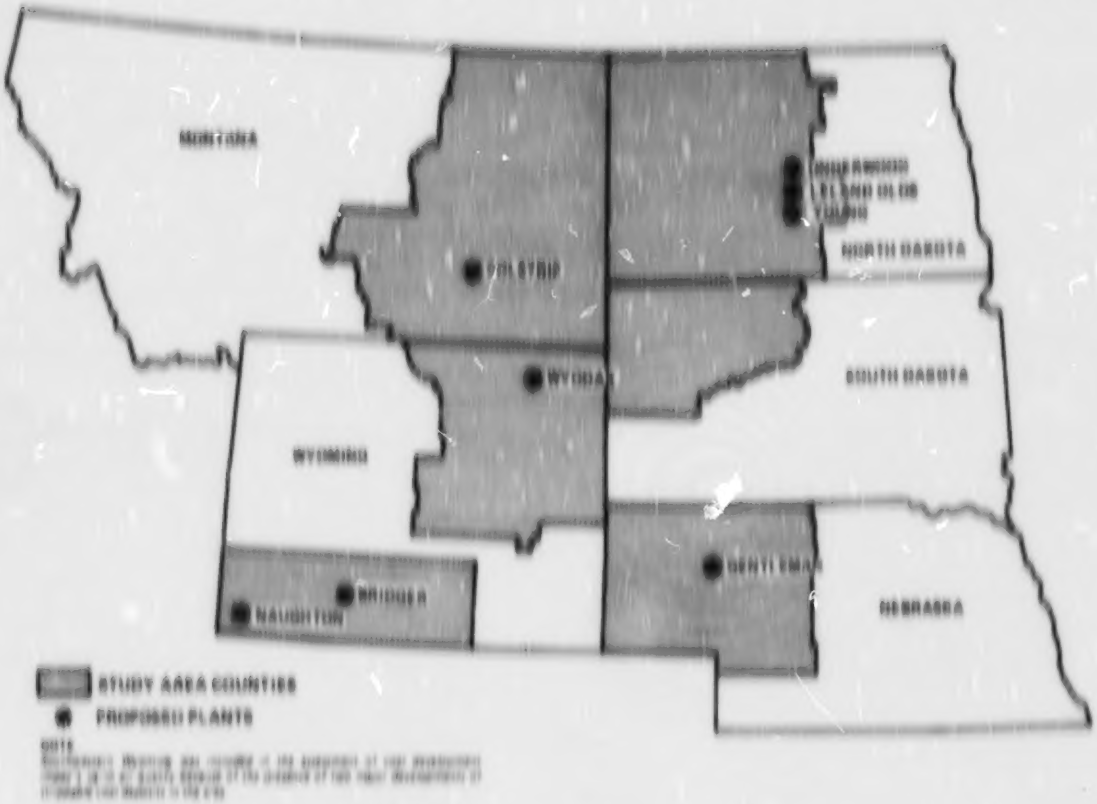

Figure IV-9. **Atmospheric aspects study area.**

layer height, which is that layer of air next to the earth's surface where relatively vigorous vertical mixing occurs. Shallower layers imply a greater potential for increased air pollution concentrations. A summary of mixing heights encountered in the study area is presented in table IV-26. These morning mixing heights are among the lowest in the United States, while the afternoon mixing heights are somewhat higher than average U.S. values.

In general, the worst dispersive conditions occur in the morning and during the winter afternoons. Few data are available on the frequency and extent of temperature inversions that cause localized stagnant airmasses and concentrate air pollutants. Data to define this phenomena for five locations in the NGP are being collected and will be available in 1976.[68]

The annual mean relative humidity for the study area is 60 percent which is lower than many other parts of the country. The study area receives between 60 and 70 percent of total possible sunshine. These are important factors because the conversion of SO_2 to sulfate is believed to be a direct function of relative humidity and because the conversion of hydrocarbons and nitrogen oxides to photochemical oxidants occurs in the presence of sunlight. The rate of formation of sulfate increases rapidly at humidities above 60 percent. Sulfur in the form of sulfate is far more toxic to living forms than is SO_2.

Presently the major manmade sources of air pollution in the NGP are farming, grain processing, power generation, mining and minerals processing (oil, soda ash, uranium),

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[68] For location of stations refer to Air Resources Work Group Report.

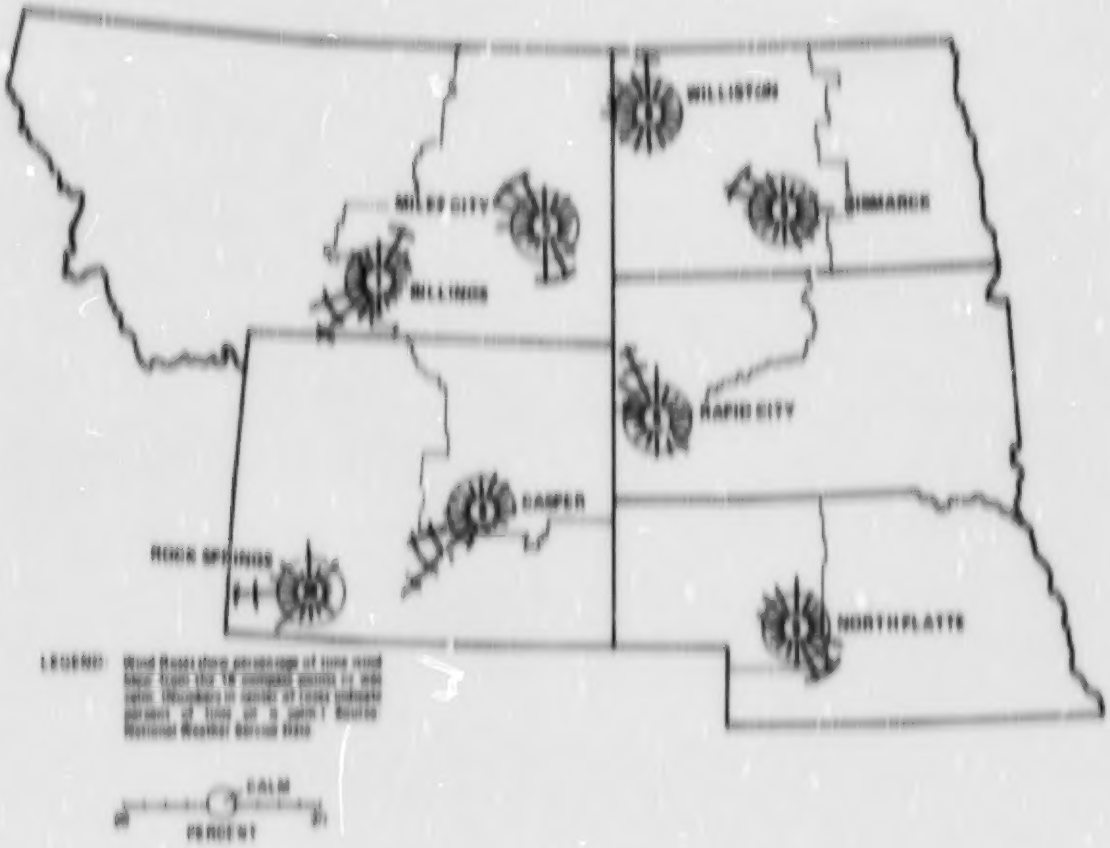
WILLISTON
BISMARCK
MILES CITY
BILLINGS
RAPID CITY
CASPER
ROCK SPRINGS
NORTH PLATTE
LEGEND:
CALM
PERCENT

Figure IV-10. Surface wind roses annual.

Table IV-26.—*Northern Great Plains mean mixing heights (meters)*[1]

	Annual	Winter	Spring	Summer	Autumn
Morning	300-400	300-400	400-500	300	300
Afternoon	1,400-1,600 (N. Dak., S. Dak., and Nebr.) 1,000-2,400[1] (Wyo. and Mont.)	600-1,000 (N. Dak., S. Dak., Mont.) 1,000-1,200 (Wyo.)	2,000-2,400 2,800 (S. Dak. and Wyo.)	2,000-3,000	1,400-2,000

[1] To convert meters to feet multiply by 3.28.

production of lumber, and motor vehicle emissions and fugitive dust from unpaved roads. The total emissions are small when compared to emissions in the Los Angeles Basin, the industrial areas of Ohio or Pennsylvania, or even the metropolitan Denver area. An estimate of the amount of five common air pollutants emitted in 1973 is shown in table IV-27. A comprehensive description of air quality in the NGP is not possible because at present there are data from only 30 air quality monitoring stations in the NGP which are located primarily in urban areas. This system was augmented with nonurban monitoring stations in late 1974 and the additional data will be available in 1975.

Figures IV-11 through IV-15 compare present pollutant concentrations[18] in the NGP to selected metropolitan areas. Also shown on these figures are the primary and secondary NAAQS (National Ambient Air Quality Standards) and State air quality standards. Primary standards have been established to protect human health. Standards have not been set for all pollutants for which there is some evidence of harmful effects. Those pollutants for which standards have been set are particulates SO_2, NO_x, CO, and hydrocarbons and oxidants. The effects of these pollutants at levels above those specified by standards occur primarily in the respiratory, pulmonary, and circulatory systems. Secondary standards have been established to protect plant and animal life, visibility, and materials.

4-13. ***Impact of Coal Conversion on Air Quality.***—a. *Primary Impacts.*—Federal and State air pollution control laws require attainment and maintenance of air quality at a level that will not adversely impact human health and welfare, animal or plant life, or materials. Therefore, it must be assumed that the emissions from coal conversion facilities or pollutants from other sources will be controlled so as not to violate these laws. For this reason, the possibility of adverse environmental effects from air pollutants is not predicted. It should be emphasized that future research may show that the present standards are not adequate or that harmful compounds are not covered by a standard. Examples are

Table IV-27.—*Estimated emissions—1973 data in thousands of tons per year*

	Northern Great Plains States				
	Montana	Nebraska	North Dakota	South Dakota	Wyoming
Particulate	256	768	116	59	154
Sulfur dioxide	413	83	88	14	73
Nitrogen oxides	110	87	144	78	106
Hydrocarbon	179	151	113	110	102
Carbon monoxide	1,287	733	567	568	470

	Major U.S. cities		
	Los Angeles	Cleveland	Denver
Particulate	86	271	12
Sulfur dioxide	115	738	27
Nitrogen oxides	573	367	139
Hydrocarbon	1,167	2,278	174
Carbon monoxide	4,128	3,372	873

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[18] Particulate concentrations at some of the NGP urban sites approach or exceed levels measured in Los Angeles, Denver, and Cleveland. It is suspected that the levels measured in the NGP are significantly, if not predominantly, influenced by "fugitive dust." Agricultural activities, mining activities, and "natural conditions" result in wind-blown dust which causes high particulate readings. Gaseous pollutant levels in the NGP are not as high as those found in the metropolitan areas mentioned previously.

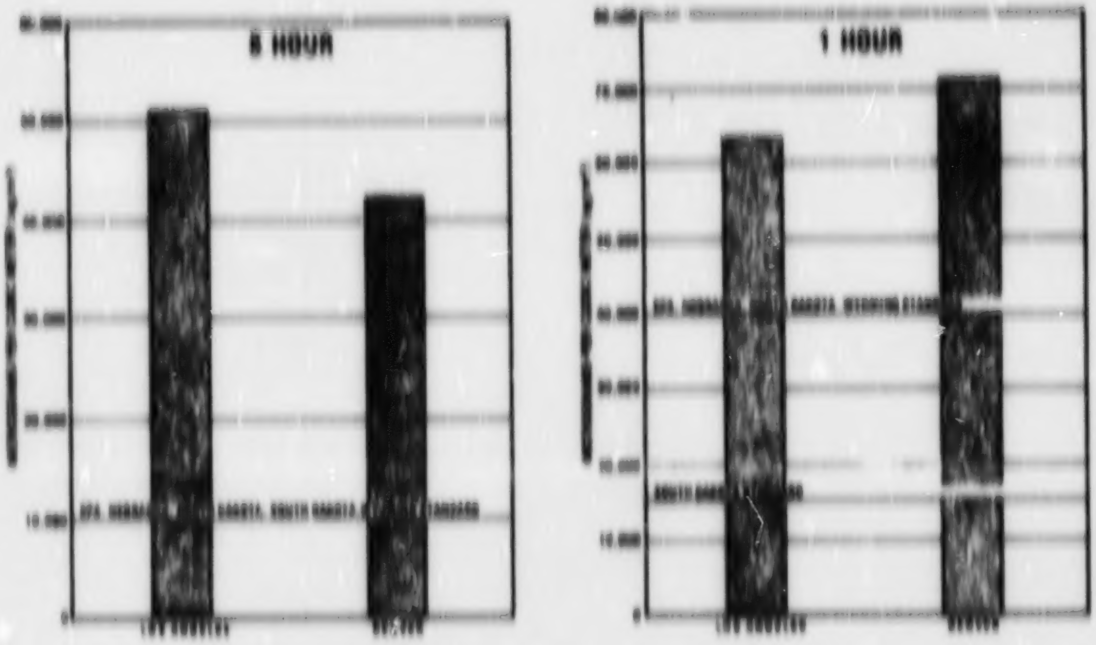

Figure IV-11. Carbon monoxide—Ambient air quality data and standards.

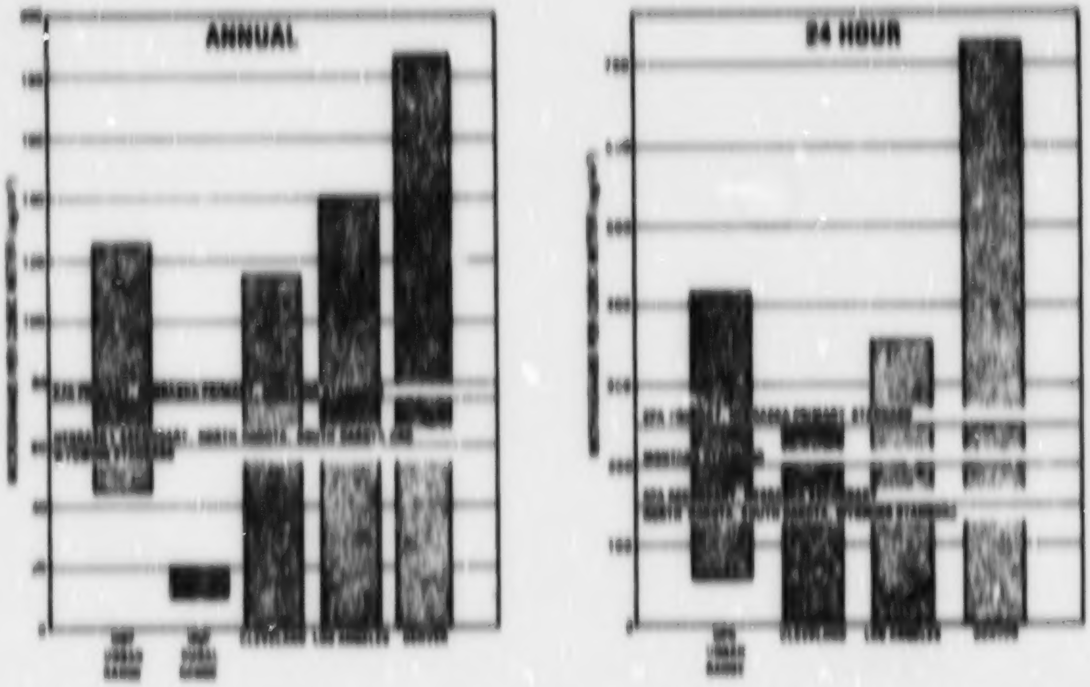

Figure IV-12. Particulate matter—Ambient air quality data and standards.

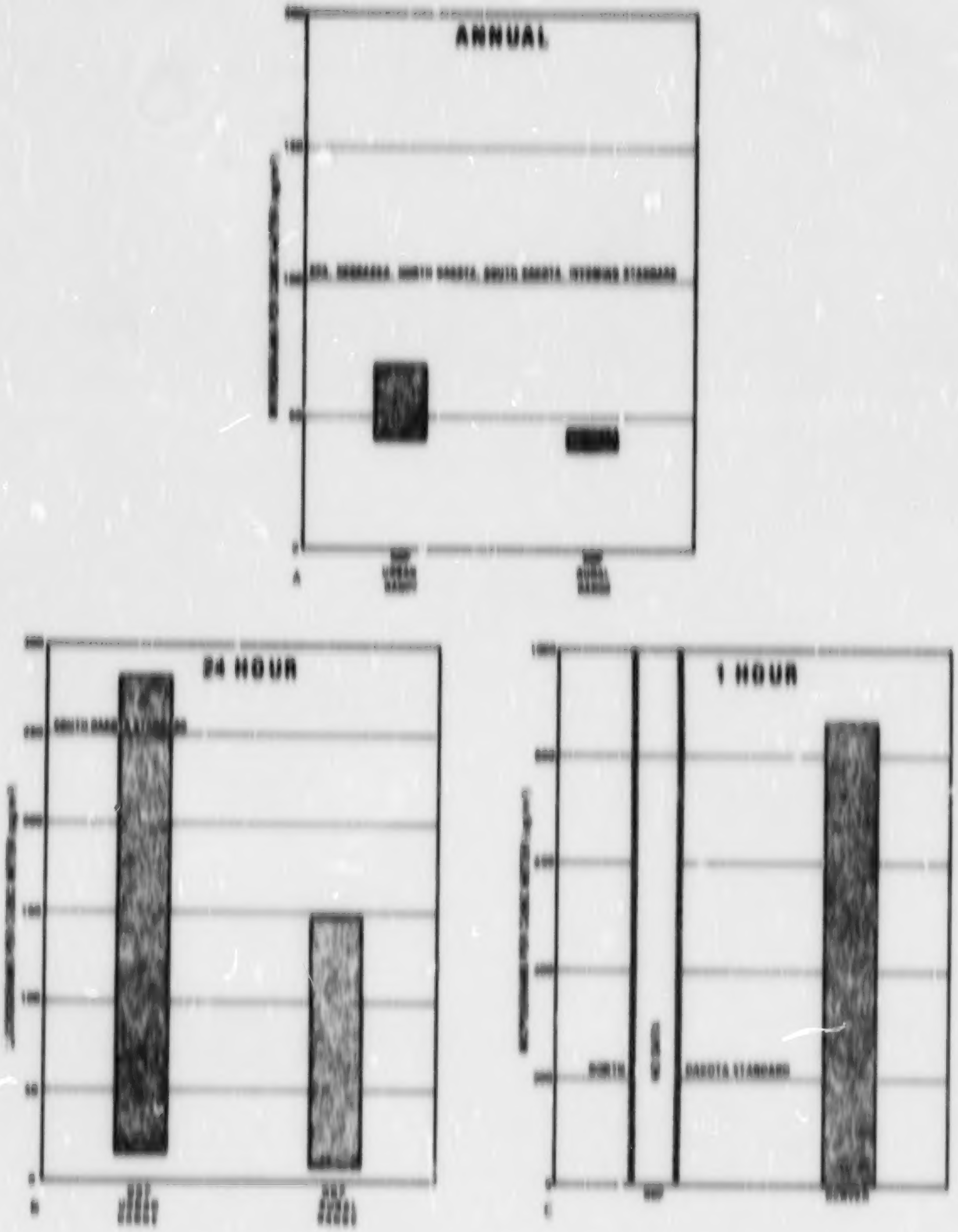

Figure IV-13 A, B, and C nitrogen oxides—Ambient air quality data and standards.

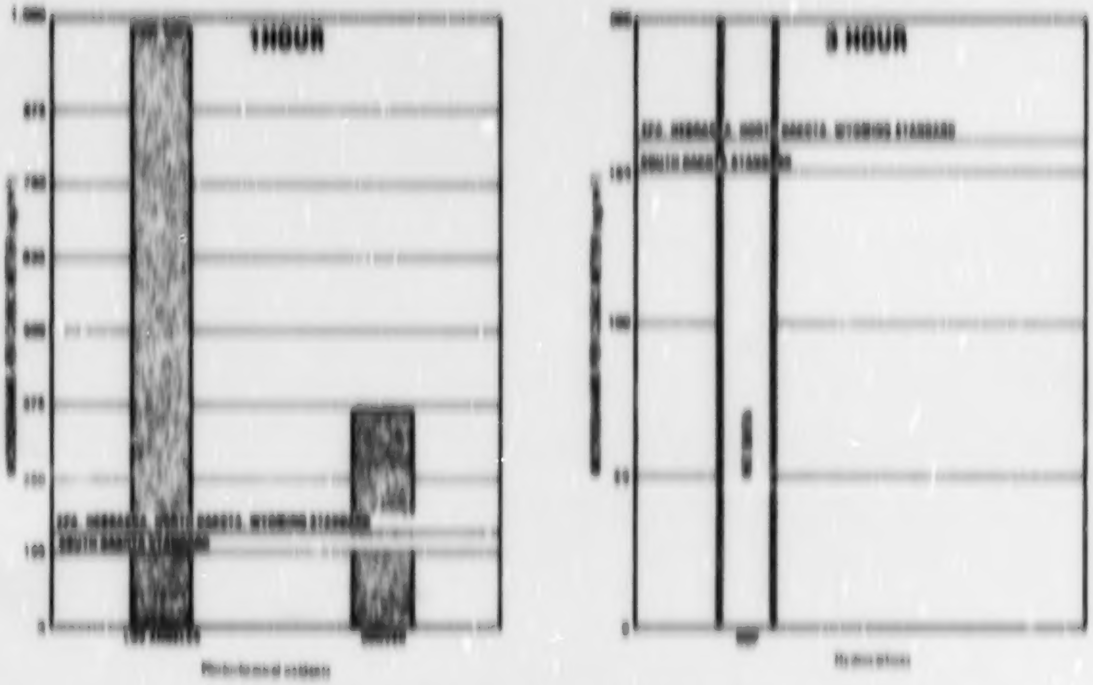

Figure IV-14. Photochemical oxidants and hydrocarbons ambient air quality data and standards.

atmospheric sulfate for which there are no standards and materials such as heavy metal whose effects become apparent only after many years of exposure. Further, the mechanism for enforcing standards—the establishment of emission regulations through the State Implementation Plans (including Air Quality Maintenance Regulations)—are far from perfect because of:

(1) Very imperfect models.

(2) Poor meteorological and air quality data.

(3) Potential for malfunctioning of control devices.

(4) Potentially poor monitoring and enforcement.

Major pollutants emitted from a powerplant will be particulates, sulfur oxides, and nitrogen oxides. Major emissions from gasification plants appear to be hydrocarbons with additional quantities of particulate, sulfur oxides, and nitrogen oxides from onsite steam generation. The potential harmful effects of these pollutants were recognized by Congress in passing various Federal Clean Air acts. As a result of the 1970 Act, the Administrator of EPA promulgated primary and secondary standards (NAAQS) for the pollutants that, in his judgment and based on then current data, have an adverse impact on health and public welfare. These standards are shown in table IV-28. Further, trace elements such as mercury, lead, beryllium, arsenic, flourine, cadmium, and selenium are emitted from coal-fired powerplants. Chemical reactions which occur in the air result in the conversion of sulfur dioxide to sulfates (such as sulfuric acid) and nitrogen oxide to nitrates. Some of these elements or compounds can be harmful to human health, to animal and plant life, and to materials. There are no Federal standards applicable to coal conversion facilities for any of these pollutants at the present time. Some of the NGP States have standards for sulfates, lead, beryllium, and fluoride. There is also evidence that fine particulates are especially harmful to human health but standards have not been set.

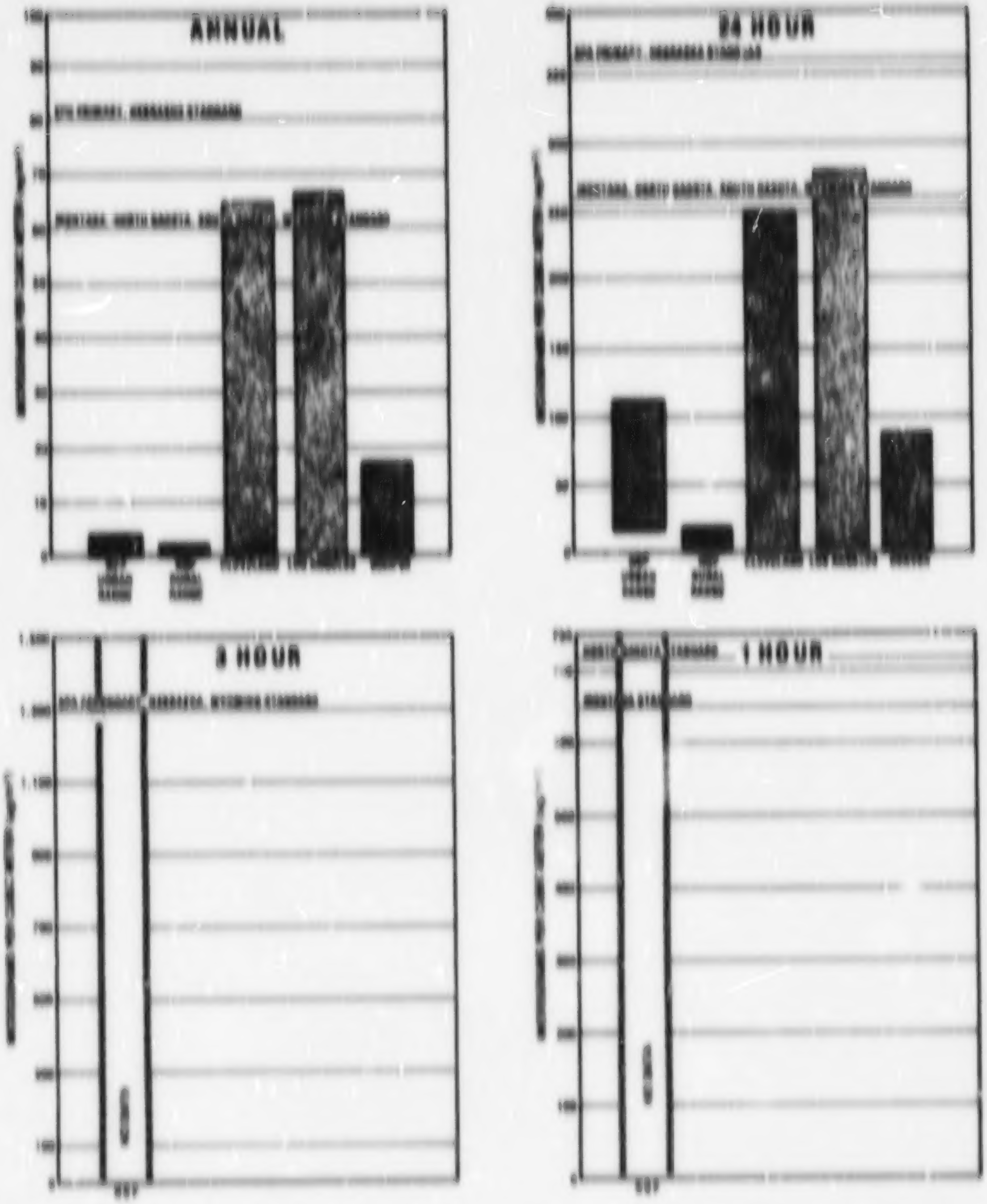

Figure IV-13. Sulfur oxides- Ambient air quality data and standards.

Table IV-28.—*NAAQS (National Ambient Air Quality Standards)*

Pollutant	Primary standard	Secondary standard
Sulfur oxides	80 µg/m³ (0.03 ppm) annual arith. mean 365 µg/m³ (0.14 ppm) max 24 hr. conc. not to be exceeded more than once a year	1,300 µg/m³ (0.5 ppm) max 3 hr. conc. not to be exceeded more than once a year
Particulate matter	75 µg/m³ annual geom. mean 260 µg/m³ max 24 hr. conc. not to be exceeded more than once a year	60 µg/m³ annual geom. mean, [1] / 150 µg/m³ max 24 hr. conc. not to be exceeded more than once a year
Carbon monoxide	10,000 µg/m³ (9 ppm) max 8 hr. conc. not to be exceeded more than once a year 40,000 µg/m³ (35 ppm) max 1 hr. conc. not to be exceeded more than once a year	Same as primary
Photo chemical oxidants (corrected for NO_2 and SO_2 interference)	160 µg/m³ (0.08 ppm) max 1 hr. conc. not to be exceeded more than once a year	Same as primary
Hydrocarbons (corrected for CH_4)	160 µg/m³ (0.24 ppm) max. 3 hr. conc. (6 to 9 a.m.) not to be exceeded more than once a year	Same as primary
Nitrogen oxides (as nitrogen dioxide)	100 µg/m³ (0.05 ppm) annual arith. mean	Same as primary

[1] To be used as guide in assessing State Implementation Plans.

NOTE: ppm = parts per million
µg/m³ = micrograms per cubic meter

In discussing the impacts of coal development on NGP air quality, a comparison to these standards will be made.

To attain and maintain the NAAQS a variety of State and Federal regulations on existing and new emission sources have been adopted. NSPS (New Source Performance Standards), (section 111, Clean Air Act, as amended), are applicable only to new sources. The standards in table IV-29 apply to all fossil-fuel-fired steam generating plants larger than about 25 megawatts whose construction began after August 17, 1971 (lignite plants are exempt from the NO_x NSPS).

These standards would require a large powerplant burning a 10 percent ash, 1.0 percent sulfur, 9,000-Btu/pound coal to control particulate emissions by 99 percent, sulfur oxide emissions by 40 percent, and nitrogen oxides emissions by 30 percent. Control of particulate matter may be achieved by highly efficient electrostatic precipitators, wet scrubbers, or fabric filters. Sulfur oxides emissions may be controlled via wet scrubbers using an alkaline media or via catalytic oxidation. Nitrogen oxides emissions are normally controlled by preventing the formation of NO by lowering the combustion temperature.

Existing sources of pollution in the States must meet regulations contained in SIP's (State Air Quality Implementation Plans) (section 110, Clean Air Act, as amended) and maintain ambient air quality standards.

There are three other related air quality standards which are relevant to this discussion. First, as part of the SIP's process each State projects its anticipated emissions through the year 1985 and estimates air quality resulting from such projections. If the analysis shows that NAAQS may be exceeded, the State must develop a 10-year air quality maintenance plan to ensure that standards are met. Montana, North Dakota, and Wyoming have counties in the coal areas which are subject to these plans. Second, a Federal indirect source regulation has been promulgated to be in effect as of July 1, 1975. The regulation requires evaluation of the impact of major highway proposals, airport proposals, and certain other facilities such as shopping centers before an application to construct is approved.

Lastly, the issue of air quality deterioration of clean air quality areas is being examined. The Clean Air Act of 1970, as amended, required a SIP to contain regulations to prevent significant deterioration where air quality is better than that required by the national standards. These regulations could be the single most important factor both to the Nation and to the NGP in terms of maintaining excellent air quality. Present regulations have defined three types of geographical zones. The standards for these three zones are shown in table IV-30. Until States act to zone their territories into one or more zones, they are classed as Zone 2.

In Zone 1 there will be essentially no decrease in air quality allowed, in Zone 2 a moderate decrease will be allowed, and in Zone 3 the air quality can be degraded to the secondary standard.

Each State will be responsible for zoning itself and enforcing the standards except for Federal lands. Indian tribes are responsible for zoning their respective reservations. This means that the people living in a particular region can establish the quality of air how they choose as long as it does not threaten human health and welfare or the selected air quality of adjacent jurisdictions.

Generally there are three atmospheric conditions that may result in concentrating airborne pollutants. The first situation occurs

Table IV-29. –*NSPS standards*

	Allowable pounds/10^6 Btu		
	Coal	Oil	Gas
Particulate	0.10	0.10	0.10
SO_2 (sulfur dioxide)	1.20	0.80	–
NO_x (oxides of nitrogen)	0.70	0.30	0.20

Table IV-30. –*Significant air deterioration limits*

	Increase permissible over 1974 levels ($\mu g/m^3$)		Existing secondary standards ($\mu g/m^3$)
	Zone 1	Zone 2	Zone 3
Particulate matter			
Annual	5	10	75
24-hour	10	30	150
Sulfur oxides			
Annual	2	15	80
24-hour	5	100	365
3-hour	25	700	1,300

NOTE: $\mu g/m^3$ is micrograms/cubic meter.

when extremely stable atmospheric conditions with steady winds for 8 to 10 hours direct a plume toward elevated terrain. This causes the pollutants to concentrate at the elevated point. The second condition, terraced fumigation, occurs when there are extremely stable conditions that result in a localized concentration of pollutants above the earth's surface followed by a rapid change to an unstable atmosphere which would cause these pollutants to settle on the earth's surface. The third condition is when extremely unstable wind conditions exist and the plume is directed to the ground very near the point of emission. Available meteorological data for the sites used in the above-mentioned studies indicate that these conditions occur very infrequently and they may not persist for sufficient duration to cause a violation of present air quality standard.

To estimate the effect of plant emissions upon present NGP air quality, pollutant concentrations were calculated using a computer model. The annual and 24-hour particulate, SO_2 (sulfur dioxide), NO_x (oxides of nitrogen), and HC (hydrocarbon) concentration estimates were made using a computer program similar to that published by Martin[57] (1971). Martin's program was modified by Burt[58] (1973) to consider the effects of elevated terrain, to utilize Briggs[59] (1969, 1970, 1971 and 1972) plume rise equations, and to provide a significant computer printout which gives concentrations at specified grid points located along 16 radials fixed by the common 16 wind directions, N, NNE, NE, ENE, and so forth. A detailed description of the model as it has been modified and the computer code is given by Burt[60] (1973). A complete description of the technique plus the assumptions are contained in the Atmospheric Aspects Work Group Report.[61] The estimates were based on powerplants that are either under construction, applying for construction permits, or are being proposed and have associated environmental studies in progress and a hypothetical gasification plant. It was assumed that emissions from each powerplant would be equal to, but not exceed, NSPS. Emissions from the hypothetical gasification plant were estimated from data supplied by companies planning the construction of coal gasification facilities. There are no SNG plants in existence or under construction in the United States at present. Therefore, emission estimates were obviously based upon design data only.

The combined capacity of these plants (fig. IV-9) correspond closely to the CDP I; therefore, impacts from these plants can be construed to be representative of CDP I impacts. This is the primary reason for the selection of these plants to be studied. Portions of these plants are operational today with the plant expansions being designed to become operational in the near future.

Table IV-31 presents the results of the modeling estimates for annual concentrations. The significant increase in concentration of pollutants are associated with the terrain features adjacent to the Naughton Plant. Similar concentration can be expected in regions with high relief.

Table IV-32 lists the "worst case" maximum

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[57] Martin, D., 1971, "An Urban Diffusion Model for Estimating Long Term Average Values of Air Quality," J. Air Poll. Control Assoc. 15, (1), pp. 16-19, January 1971.

[58] Burt, E. W., 1973, "Description of Terrain Model ([illegible])" (Manuscript in Preparation) MDAD, SRAB, Modeling Application Section, U.S. EPA, Research Triangle Park, North Carolina 27711.

[59] Briggs, G. A., 1969, "Plume Rise" U.S. AEC, Critical Review Series TID-25075, National Technical Information Service, Springfield, Va 22151.

[59] Briggs, G. A., 1971, "Some Recent Analyses of Plume Rise Observations," pp. 1029-1032, Proceedings of the Second International Clean Air Congress, edited by H. M. Englund and W. T. Beery, Academic Press, New York City.

[59] Briggs, G. A., 1972, Discussion on Chimney Plumes in Neutral and Stable Surroundings, Atmospheric Environment, vol. 6, pp. 507-510, July 1972.

[60] Op. cit., p. 109.

[61] Atmospheric Aspects Work Group Report," Northern Great Plains Resources Program, 1974, may be found at repositories listed at the end of appendix B.

Table IV-31.—*Estimated annual air quality concentrations*[1]

Plant	Maximum concentration, $\mu g/m^3$		
	Particulate	SO_2	NO_x
Colstrip	0.2	2.1	1.4
Naughton	0.7	8.2	6.0
	[2] 6.0	[2] 68.0	[2] 50.0
Bridger	0.3	3.3	1.9
Underwood	0.04	0.4	0.4
Leland	0.03	0.5	0.3
Gentleman	0.08	1.0	0.6
Young	0.05	0.3	0.3
Wyodak	0.1	1.3	0.7

[1] Background pollutant concentrations not included.

[2] With terrain considered.

NOTE: $\mu g/m^3$ is micrograms per cubic meter.

predicted groundlevel 24-, 3-, and 1-hour concentrations.

All of the concentrations listed in tables IV-31 and IV-32 are *representative only of the contribution from the plant*; that is, no existing pollutant concentrations (background) are included. Background must be added to obtain an estimate for comparison against relevant ambient standards.

Particulate concentrations that could be considered as representative background values are now being measured in the NGP region. Three months data show average values of 27 $\mu g/m^3$. The average maximum and minimum values of 26 stations are 55 $\mu g/m^3$ and 11 $\mu g/m^3$, respectively. Similar measurements for SO_2 and NO_x indicated background concentrations essentially zero. If these values are added to the estimated powerplant contribution as shown in table IV-32, one gets a picture of the particulate concentrations which may be recorded when the plant comes on line. This information shows no potential violations. Conclusive statements cannot be made for CDP II or CDP III.

Figures IV-16 and IV-17 illustrate the comparison between the applicable air quality standards and the estimated impact upon air quality as a direct result of the powerplant. It should be noted that these figures estimate the worst that could happen but do not estimate the frequency of occurrence of such an event. The probability of occurrence is determined by the frequency of occurrence of a given meteorological condition.

The modeling analysis of the eight powerplants for SO_2 and particulates show that (fig. IV-16 and IV-17) no State or Federal standards will be violated.

The predicted annual average SO_2 concentrations in the vicinity of the Naughton

Table IV-32.—*Estimated short-term air quality concentrations*[1]

Plant	Maximum 24-hour concentrations		Maximum 3- and 1-hour SO_2 concentrations	
	Particulate	SO_2	3-hour	1-hour
Colstrip	14	164	410	665
Naughton	10	126	315	511
Bridger	11	137	341	553
Underwood	5	62	154	250
Leland Olds	4	47	118	192
Gentleman	6	77	192	310
Young	7	79	197	320
Wyodak	4	51	123	200
Gasification plant	—	—	1,634 (hydrocarbons)	—

[1] All data in micrograms per cubic meter ($\mu g/m^3$).

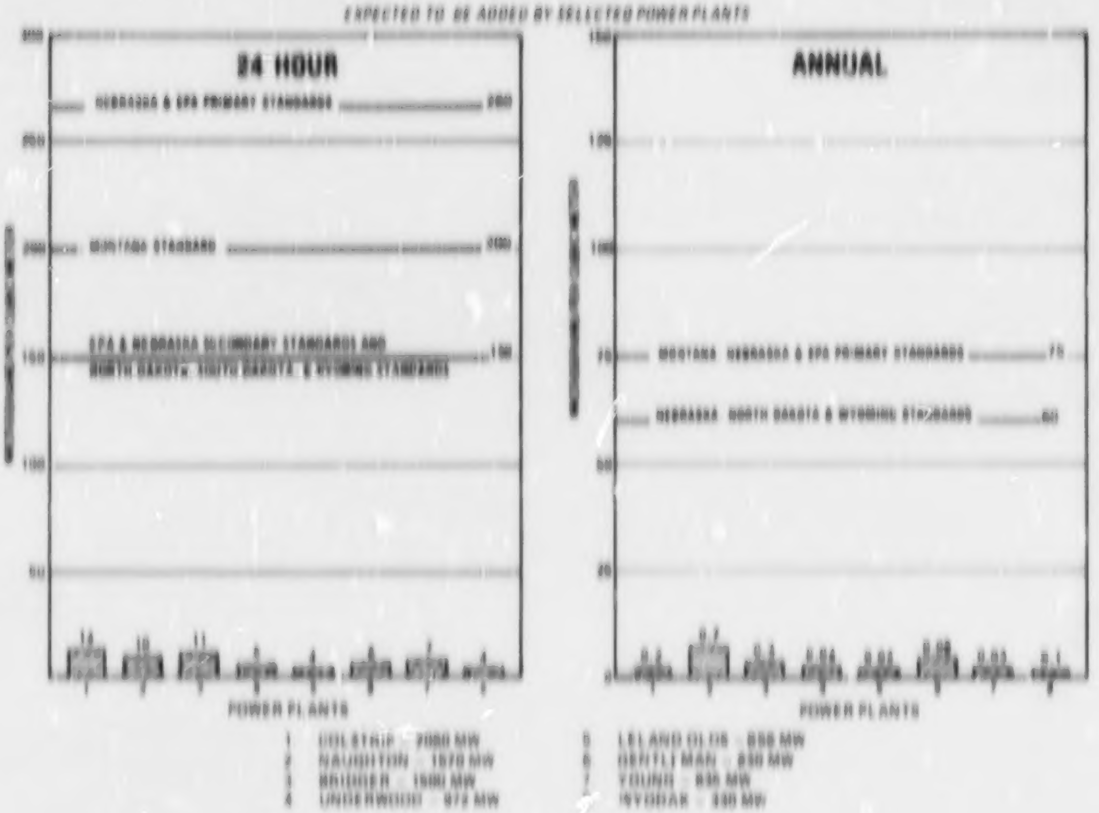

Figure IV-1c. **Maximum ambient particulate concentrations.**

Plant approach the Wyoming and Federal standards. When corrected to Wyoming elevation, the 68 $\mu g/m^3$ concentration equates to about 55 $\mu g/m^3$. These values compare with the Wyoming standard of 60 $\mu g/m^3$ and the EPA primary standard of 80 $\mu g/m^3$.

Diffusion modeling provided air quality estimates of about 1,634 $\mu g/m^3$ for a 3-hour hydrocarbon concentration associated with the gasification plant. This value is well above the allowable standard of 160 $\mu g/m^3$. Therefore, the proposed gasification plants must have better control of their hydrocarbon emissions than was assumed by this modeling study. This control can be accomplished by incineration, adsorption, absorption, or catalytic conversion. Three environmental reports[61] released by companies planning gasification plants indicate that hydrocarbon emissions will make essentially no contribution to air quality concentrations.

An estimate of the pollutant concentrations compared to standards was not made for specific plants in either medium or high CDP's because of a lack of specific plant data and site's specific meteorological data. An air quality and meteorology monitoring network has been established to complement the existing data-gathering efforts. Monitoring is being conducted at 22 new sites in the region

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[61] El Paso Coal Gasification Project, 1974, Draft Environmental Impact Statement, Bureau of Reclamation; Wesco Coal Gasification Project, 1974, Draft Environmental Impact Statement, Bureau of Reclamation; An Applicant's Environmental Analysis for the Wyoming Coal Gas Project, Panhandle Eastern Pipeline Company and Peabody Coal Company, October 1974.

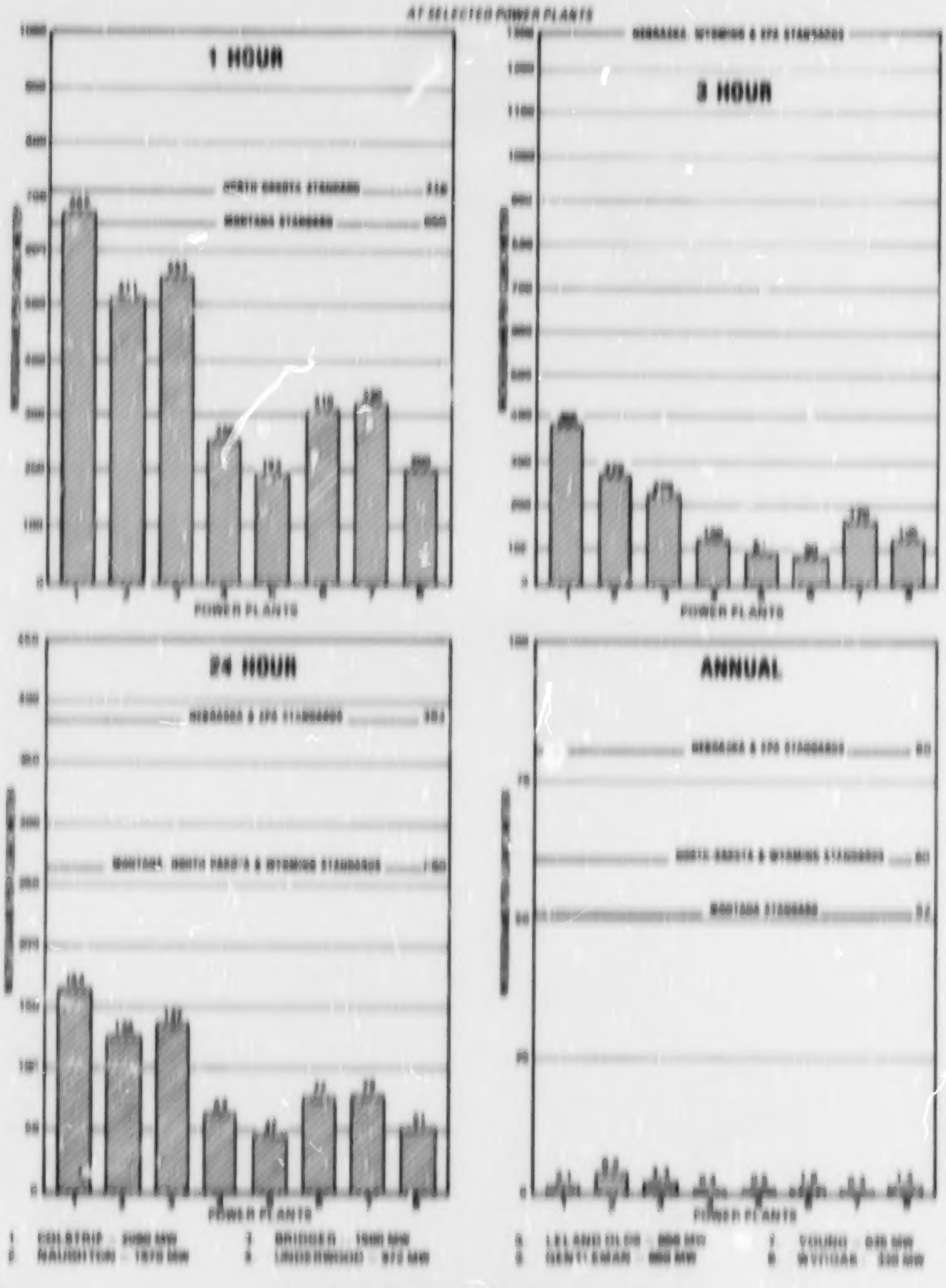

Figure IV-17. Maximum ambient SO_2 concentrations.

in addition to the 30 existing sites. These new data, combined with existing regional meteorological data-gathering activities, will enable the use of a regional model approach which is necessary to assess the interactions of several plants upon some remote area.

Although modeling was not performed, the pollutant emissions introduced into the atmosphere by power and gasification plants at each of the three CDP levels for five pollutants were estimated. Table IV-33 lists those emissions. For comparison purposes, refer to the previously presented emissions in Table IV-27.

About 431,000 tons of particulates are presently emitted each year in Montana, North Dakota, and Wyoming. This does not include naturally occurring dust or particulates blowing off disturbed soils. CDP's I, II, and III would increase emissions by 18, 31, and 42 percent, respectively, by the year 2000. SO_2 increases would be 208, 357, and 451 percent; NO_x increases will be 193, 324, and 394 percent; hydrocarbon emissions will increase by 5,363 and 914 percent; and CO emissions will increase by 3, 5, and 6 percent, respectively, for CDP I, II, and III. The coal-bearing area, however, is much smaller than the three States and the increased loading would be many times what is now introduced into the area. The degree to which the plants were concentrated would have a strong influence on the reduction of visibility. After data now being collected are analyzed, the extent to which visibility will be reduced can be better estimated.

The effect of the increased atmospheric loadings of particulate matter, especially the significant increase in fine particles and aerosols upon visibility from coal conversion and mining, is extremely difficult to predict. A decrease in visibility is predicted but the extent of reduction cannot be quantified from present data. Fine particles, such as those in the 0.1 to 1.0 micron (radius) size range, dominate the light-scattering phenomenon and hence degrade visibility. It is important to observe that most

Table IV-33.—*Estimated emissions from projected coal conversion facilities in tons per year*

	Powerplants			Coal gasification plants		
	CDP I	CDP II	CDP III	CDP I	CDP II	CDP III
Particulate						
1985	22,810	22,810	22,810	0	13,370	38,200
2000	44,897	65,545	65,545	0	30,560	78,310
Sulfur oxides						
1985	273,828	273,828	273,828	0	150,710	430,600
2000	539,123	787,038	787,038	0	344,480	882,730
Nitrogen oxides						
1985	159,642	159,642	159,642	0	72,520	207,200
2000	314,289	458,815	458,815	0	165,760	424,760
Hydrocarbon						
1985	4,803	4,803	4,803	0	609,490	1,741,400
2000	9,451	13,798	13,798	0	1,398,120	3,569,870
Carbon dioxide						
1985	16,202	16,202	16,202	0	5,320	15,200
2000	31,898	46,566	46,566	0	12,160	31,160

present-day pollution control techniques are relatively inefficient collectors of submicron particles. These small particles are also the most significant in terms of causing health effects problems due to the ease with which they may penetrate the respiratory system.

b. *Secondary Impacts.*—Only the direct environmental impacts of the coal conversion facilities were factored into the modeling effort. Secondary impacts may have a significant impact upon air quality. Mining activities and the attendent population growth are the major identifiable "secondary impacts." It is extremely difficult to quantify secondary impacts. However, work is being done to provide data which may enable quantitative assessment. Only a qualitative discussion may be presented at this time.

An increase in particulate matter, in the form of fugitive dust, is known to occur as a result of any strip-mining activity. Also because of the activities of people required to support the coal conversion facility, there will be an increase in other emissions as well.

c. *Potential Constraints to Coal Conversion.*—Present law requires that ambient air quality standards must be attained and maintained throughout the NGP. Air quality impacts as a result of the construction of powerplants at the CDP I level would appear not to affect maintenance of the standards. However, Zone 1 and possibly Zone 2 designation would constrain development under the significant deterioration regulations. Plant sitings, plant size, and degree of emission control may be influenced by this resolution.

Technology for control of hydrocarbon emissions from gasification plants must be improved if hydrocarbon air quality standards are to be maintained. The degree of the control technology will be one factor in the determination of the extent of development.

Development at CDP II and III levels may be constrained by air quality standards.

4-14. ***Research and Analysis Needs.***—Some research needs are necessarily regional in nature while others have national impacts. It is anticipated that through the NGPRP some data may be collected to provide input to those national needs. The following paragraphs pertain to air pollution considerations for which additional research is needed.

The significant increase in SO_2 emissions, hence atmospheric loadings, creates the potential for a decrease in the pH; that is, the measurement of acidity of rainfall in the NGP and Midwestern States. The amount of this pH decrease cannot be determined with any degree of accuracy on a theoretical basis without making a wide set of assumptions. Measurement of pH at a number of rain collection stations in the NGP should be initiated. In so doing, baseline data may be gathered with subsequent measurements identifying the impact of the constructed coal conversion facilities. This is potentially serious because acid rains could result, increasing corrosion-causing health problems and affecting productivity of vegetation. Such acid rains may increase corrosion, cause health problems, and affect productivity of vegetation.

The potential for photochemical oxidant formation in the vicinity of coal gasification complexes appears to be significant. Such oxidants are serious in causing eye irritation, pulmonary tract damage, and deleterious effects on vegetation. The Los Angeles-type brown smog is a case of photochemical oxidant formation. The combination of hydrocarbon emissions from the gasification process, the nitrogen oxides emission from the attendant steam generating plant, and a high frequency and intensity of sunlight in the NGP States provide all the ingredients for potential oxidant formation. A network of hydrocarbon, NO_x and oxidant ambient air quality monitors should be established in the areas of potential gasification plants to obtain baseline data. An ongoing network of oxidant monitoring should continue well into the future to determine the impact of facilities as they come on line.

Effects of the pollutants for which there are Federal standards and of trace pollutants from coal conversion facilities upon young vegetation in reclaimed areas should be evaluated. A research study being conducted by the National Environmental Research Center at Corvallis, Oregon, will address this topic to a certain degree. More effort should be directed toward this activity.

The aspect of the increased particulate matter in the atmosphere acting as additional cloud condensation nuclei should be studied. Both increased and decreased precipitation have been theorized as a result of this phenomenon. This is an important matter because of the potential for causing regional climatic change.

The atmospheric concentrations and effects of increased CO_2 (carbon dioxide) emissions should be evaluated. Monitoring sites could be identified where CO_2 levels would be measured over a long period. This is one of the causes of the theorized world-wide "greenhouse effect."

Health and welfare effects of increased atmospheric loadings of sulfates and nitrates should be studied.

Incorporation of such studies in the Community Health Environmental Surveillance Study would provide beneficial information. Sulfates and possibly nitrates are being shown to have serious health effects on humans and animals.

The increased levels of fine particulate matter in the atmosphere and the potential light attenuation and solar insolation effects should be the subject of further in-depth research. There is not sufficient information available to predict how serious the reduction in visibility would be and there is insufficient knowledge on potential regional and world-wide climatic changes.

Trace elements contained in coal which is converted into electricity or SNG will be released to the atmosphere. There are data regarding the concentration of certain trace elements in samples of NGP coal. These data are presented in the Mineral Resources and Air Resources Work Group reports. There are limited data presented in the Air Resources Work Group report regarding ambient atmospheric concentrations of trace elements in the NGP. Limited data have also been made available regarding trace element concentrations in soils and vegetation. Only limited data are available which would allow a determination of the concentration at which a given trace element is harmful to the public health and welfare. Exceptions are those data on elements such as mercury, beryllium, and maybe flourine. Other elements are being studied by NAS, EPA, and others. Data are not available to complete the chain from the trace element concentration in the coal to the ambient concentration and its subsequent effect. Research to fill these data gaps is needed.

Baseline studies of trace elements and the fate of trace elements emitted from coal conversion facilities are beginning to be studied[88]. Much more work needs to be done in this area as well as determining their potential impacts. This could be very important in determining which coals should be mined to minimize trace element pollution.

As an example, there are preliminary indications that trace elements tend to be preferentially concentrated in the smaller particle size range. If this is so, then the health problems caused by small particulates may be even more serious than anticipated because these are the particles that may be deposited in the lungs. A theory of volatilization and subsequent adsorption onto the small particle surface area has been put forth as an explanation. Almost no extensive studies have been performed on this topic, but they are needed.

There is a continuing need to develop new and more efficient pollution control devices to prevent the pollutants produced by the mining and conversion of coal from entering the natural ecosystems.

Detailed meteorological measurements at site specific plant locations should be made. The horizontal and vertical characteristics of the atmosphere must be known or estimated in order to predict atmospheric pollutant concentrations. Also, plume rise measurements should be made at existing plants in order to evaluate currently used estimation techniques. Wind shear patterns at potential plant site locations should also be studied. Accurate measurement of these parameters should improve air quality diffusion modeling accuracy. Current models are only reliably accurate to within a factor of two.

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[88] Geochemical Survey of the Western Coal Regions, First Annual Progress Report, July 1974, U.S. Geological Survey, Denver, Colorado, Open-file Report No. 74-250, 1974.

PART V—THE ECONOMIC, SOCIAL, AND CULTURAL IMPACTS OF COAL DEVELOPMENT IN THE NGP

5-1. ***Introduction.***—Large-scale coal-energy development may have a profound impact upon the structure of the economy, institutional fabric, and social structure of the NGP. It is an extremely difficult task to accurately assess what impact coal development will have upon the people of the NGP. Some impacts are quantifiable, while others can only be addressed subjectively. It is in this framework that the economic, social, and cultural impacts are addressed.

Some of the issues to be discussed in this section are:

- How will coal mining and coal conversion facilities change the employment patterns and levels in the Northern Great Plains?
- How much, how fast, and where will the population of the region grow?
- How will the population increases affect the availability of housing, educational facilities, and municipal services?
- What tax revenues will be generated by coal development and will they be available in sufficient amounts and in time to meet the needs of local and state governments?
- How will coal development affect the agricultural industry?

Impacts stemming from increased coal development will touch nearly every sector in the NGP study area, be it the economy, government institutions, or the social system. Coal development will affect the economy by creating new and expanded job opportunities as well as higher levels of income in the region. Population growth associated with coal development will mean unprecedented population increases in local areas, both in terms of magnitude and the speed with which it will occur. Also, the ability of the present institutional structures will be severely tested in these localities. Higher levels of service will be required as well as new services to meet the demands of the existing and new population. Complicating the increased institutional demands is the potential of time lags between when services are needed and when new revenues are available. This will be especially critical during the initial construction phases. Social systems will be altered and strained as new people with new and different lifestyles are imposed upon a well-established social system.

Coal development is a regional problem as it will affect individuals and localities over a wide geographic area. Nonetheless, it is the local people and institutions which will have to address this problem and resolve the issues. Although each community must assess its own special problems it is doubtful if many of the localities in the NGP are really prepared or capable of accomplishing the task without planning and legislative assistance.

Considerable uncertainty remains regarding the socio-economic impacts of coal development in the NGP. Because of the complex nature of coal development, it is extremely difficult to quantify and assess the cumulative socio-economic impacts. Whether these impacts will be critical will depend on the timing and magnitude of development. Is the impact of two mines or powerplants in the same area twice as great as the impact of one, is it larger, or is it smaller? Furthermore, how adaptable is the socio-economic environment? Do equal increments of change require equal adjustments or do they require successively more? It is quite possible that the impacts resulting from the assumed coal development profiles in the NGP may be greater than the projection and analytic techniques used have been able to delineate.

From within the States of Montana, Nebraska, North Dakota, and Wyoming, 36 counties were selected as the "principal impact areas" (see fig. V-1). Similarly, from within these impact areas a number of communities were designated as "principal impact communities." Common to both "areas" and "communities" is the fact that they contain the heaviest concentration of present and proposed coal development activity. It is anticipated that they will receive the heaviest impacts generated by such activity should the

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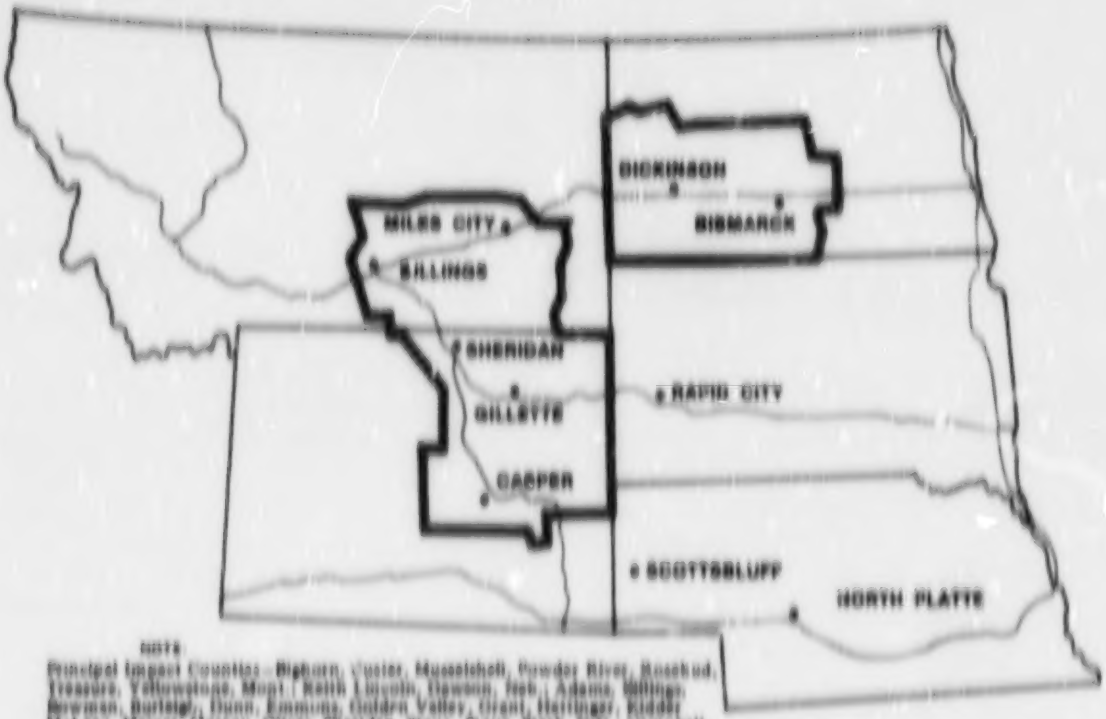

NOTE
Principal Impact Counties—Bighorn, Custer, Musselshell, Powder River, Rosebud, Treasure, Yellowstone, Mont.; Keith Lincoln, Dawson, Neb.; Adams, Billings, Bowman, Burleigh, Dunn, Emmons, Golden Valley, Grant, Hettinger, Kidder, McLean, Mercer, Morton, Oliver, Sheridan, Sioux, Slope, Stark, N.D.; Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, Weston, Wyoming

Figure V-1. Northern Great Plains States, principal impact area and major cities.

development occur as projected.

Many Indian reservations will be affected by coal development. Some reservations contain considerable coal deposits and some reservation lands have been leased. Coal development will present a different set of impacts for the Indian peoples. The Crow Nation was the only Indian nation studied. More research is needed with regard to the impact of coal development on all NGP Indian Nations and the areas adjacent to their reservations.

The major economic activity having the longest tradition and widest influence in the four-state area is agriculture. Therefore, it was selected for consideration of the impacts imposed by coal development. Within agriculture, labor, water, and land were selected as the most meaningful expressions of impact.

Appropriate economic indicators that were selected for measurements of change within the "impact areas" and "impact communities" included employment, personal income and earnings, population, highways, education, and housing.

The intent here is to indicate, on a sample basis, the kind and magnitude of changes that coal development may be expected to generate. It is emphasized that additional studies that are more site-specific, more precise, and more definitive will be needed to support land-use planning, rural and community development, and State and regional decisionmaking. It should be also recognized that the secondary impacts of coal development on adjacent States have not been assessed and require further consideration.

5-2. *The Principal Impact Area and Changes Expected as a Result of Coal Development.*—Changes in employment, population, and other socio-economic indicators were projected based on the number and timing of coal-related developments assumed in the three coal development profiles. These projected developments are shown in table V-1.

Table V-1.—*The coal energy development facilities implemented by CDP by type and by year for Montana, North Dakota, and Wyoming*

	1980			1985			2000		
	Export[1]	Electric[2]	Gas[3]	Export[1]	Electric[2]	Gas[3]	Export[1]	Electric[2]	Gas[3]
CDP I									
Montana	0	0	0	0	0	0	1	4	0
North Dakota	0	0	0	0	0	0	1	1	0
Wyoming	0	0	0	0	0	0	1	1	0
Total	0	0	0	0	0	0	3	6	0
CDP II									
Montana	1	0	0	2	0	3	2	4	3
North Dakota	0	0	0	1	0	2	1	6	5
Wyoming	1	0	0	1	0	2	2	1	1
Total	2	0	0	4	0	7	5	11	9
CDP III									
Montana	1	0	3	5	0	5	17	4	7
North Dakota	0	0	4	1	0	2	2	6	11
Wyoming	1	0	0	5	0	6	19	1	3
Total	2	0	7	11	0	13	38	11	21

[1] Export mines vary in size from 2.0 million tons/year to 10.0 million tons/year

[2] Montana—1,025-megawatt facilities; North Dakota—1,250-megawatt facilities; and Wyoming—1,200-megawatt facilities.

[3] Gasification plants are 250 million cubic feet/day facilities.

a. *Employment*.—Total employment projections[14] for the principal impact area within the States of Wyoming, Montana, Nebraska, and North Dakota are summarized in table V-2. The increase in employment in these four areas between 1970 and 2000 ranges from 28 percent for CDP I to 143 percent for CDP III. Total employment under CDP III increased by 148 percent within the principal impact area in Wyoming, 159 percent in Montana, 172 percent in North Dakota, and 32 percent in Nebraska between 1970 and 2000.

As noted in Table V-3, growth from operational employment will be strong but reasonably stable over the period of development, while construction employment will fluctuate considerably. The large construction work force and associated population in impacted areas will rise, peak, and then decline to nearly zero. An example of

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[14] The estimates presented reflect both direct employment in coal mining and conversion facilities and indirect employment for the operational as well as the construction phase of development. Employment that would be created by satellite industries that might locate near large gasification or power plants is not included. Indirect employment is employment created in the other sectors (both basic and services) to meet increased demand with coal development. Therefore, the estimates may be conservative. No employment projections for South Dakota are presented because the selected principal impact areas did not involve South Dakota. The estimates also include present coal-energy employment.

Table V-3.—*Total employment—Principal impact area 1970-2000 (in thousands)*

	1970	1980	1985	2000
CDP I				
Montana	46	56	53	63
North Dakota	53	60	55	64
Wyoming	42	48	51	54
Nebraska[1]	22	26	27	29
Total	163	190	186	210
CDP II				
Montana	46	57	75	80
North Dakota	53	60	71	105
Wyoming	42	52	59	67
Nebraska[1]	22	26	27	29
Total	163	195	232	281
CDP III				
Montana	46	76	88	119
North Dakota	53	90	82	144
Wyoming	42	57	78	104
Nebraska[1]	22	26	27	29
Total	163	249	275	396

[1] The same figures were used for Nebraska in all profiles.

this wide fluctuation in construction employment is presented in figure V-2 for Campbell County, Wyoming.

As an indication of the employment that would stem from coal development in CDP III, agriculture[61] would no longer be the principal basic employment sector in the area. Coal energy would become the dominant sector in both Wyoming and Montana, overshadowing agriculture and petroleum in Wyoming, and agriculture and manufacturing in Montana. In CDP I and II, coal employment would be expected to remain below agriculture employment.

Figure V-3 illustrates the relative magnitude of change in agricultural employment relative to coal-energy-related employment in the CDP's. The effects that coal development might have on agricultural employment are not portrayed in this illustration, that is, agriculture employment is assumed to be the same for each CDP. The coal-related direct operating employment by CDP and agricultural employment projections for Montana, North Dakota, and Wyoming are contained in tables V-4 and V-5.

b. *Population.*—Population projections in the principal impact area are summarized by year and CDP in table V-6. The total population growth for this area between 1970 and 2000 ranges from 19 percent for CDP I to 116 for CDP III. Under the assumptions of CDP III, the population of the principal impact area will increase from 434,000 to 939,000 between 1970 and 2000. This would be in marked contrast to the population growth of only 1 percent experienced in this area during the decade of the 60's.

As the data presented in table V-6 suggest, only a small increase in population in the principal impact area is expected to occur in CDP I. Although growth of approximately 5 percent would be experienced between 1980 and 2000, most of it is expected to arise in the other basic sectors as very little expansion of coal mining is assumed after 1980. Consequently, the area should return to its historically modest rate of growth after 1985.

In CDP II, population would increase to approximately 679,000 by year 2000, representing an increase of 56 percent over the impact area's 1970 population. Several factors would account for this rather significant growth rate. The principal reason is that CDP II assumes substantially greater coal mining beyond the CDP I level for the impact area. In addition, coal gasification is introduced in this profile as a source of employment and economic growth. North Dakota has a large increase in electrical power generation in addition to coal gasification (table V-1). As a

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[61] Although agriculture presently is the primary source of basic employment in the four States, it is declining in its relative importance. During the decade from 1960-1970, total agricultural employment declined by more than 30 percent in the four-state area. In other industrial sectors, mining gained 3 percent while manufacturing increased by more than 12 percent.

Table V-3.—*Estimated employment related to coal development in principal impact areas* (in thousands)*

Area	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Montana									
Direct operating	1	1	2	1	4	7	4	9	17
Construction	1	0	1	1	3	1	4	3	2
Indirect	7	3	7	7	20	17	22	26	40
Total	9	4	10	9	27	25	30	38	59
North Dakota									
Direct operating	1	1	1	1	3	10	5	8	22
Construction	1	0	0	1	3	4	7	3	7
Indirect	4	1	3	4	12	32	24	19	57
Total	6	2	4	6	18	46	36	30	86
Wyoming									
Direct operating	1	1	1	1	3	4	1	7	14
Construction	0	0	0	2	1	0	5	3	0
Indirect	2	2	3	6	9	12	12	24	20
Total	3	3	4	9	13	16	18	34	34
State totals (principal impact area)									
Direct (operating and construction)	5	3	5	7	17	26	26	33	62
Indirect	13	6	13	17	41	61	58	69	117
Total	18	9	18	24	58	87	84	102	179

*Nebraska estimates were never greater than 500; therefore, estimates for this State were not included in this table. Zero's indicate less than 500 employees, or no activity in that sector.

result of increased coal conversion plants and increased coal export, a substantial increase in construction and operating employment and associated population growth can be expected.

Population growth under CDP II is relatively small when compared to the population growth that would occur under CDP III. In CDP III a significantly greater number of coal gasification plants and export coal mines is assumed. As a result, population in the principal impact area would be expected to increase by over 100 percent during the 30-year period between 1970 and year 2000.

Although the CDP's assume that new facilities come on line throughout the study period, growth rates in the principal impact areas will vary depending upon the scheduling of coal-related developments (see fig. V-4). For instance, Wyoming, under CDP I, has a projected growth in population of 17,000 from 1970 to 1980, and only 8,000 from 1980 to 2000. North Dakota, because of a projected decrease in construction employment based on the coal development profile under CDP's I and III, can be expected to experience a population decrease between 1980 and 1985, and expansion from 1985 to 2000.

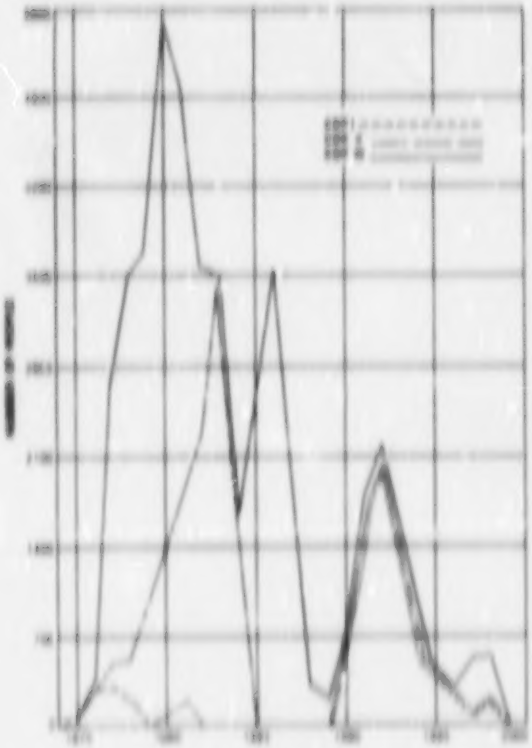

Figure V-2. Estimated annual average construction employment during construction of facilities for mining, electrical plants, and gasification plants, Campbell County, Wyoming 1975-2000.

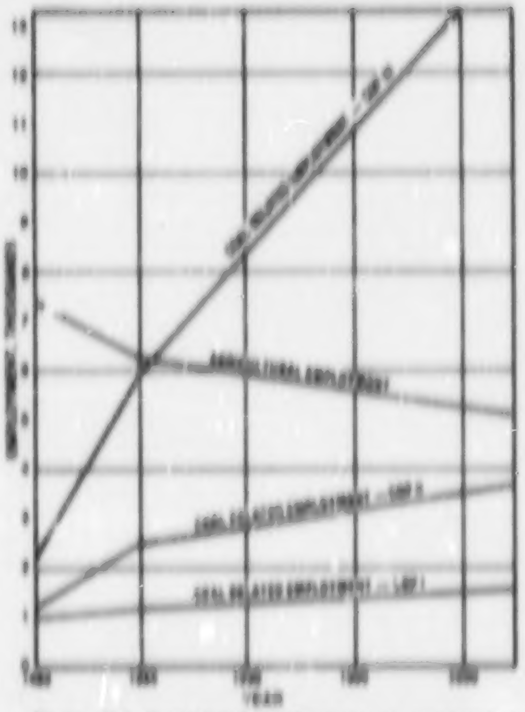

Figure V-3. Coal-related employment as compared to agricultural employment in principal impact area—Montana and Wyoming 1980-2000.

(1) *Migration.*—In the recent decade—1960 to 1970—45,000 people migrated from the principal impact area. This represents a 10-percent net emigration rate for the 10-year period. North Dakota lost the greatest number of inhabitants (27,000), followed by Montana (8,000), Wyoming (6,000), and Nebraska (4,000). Future migration patterns will vary among the CDP's and within impact areas.

There are a number of considerations regarding migration that require additional in-depth research. Some of these topics are:

- Sources of labor both from within and outside the area
- Wages necessary to attract workers
- Competition for existing labor force and the effects stemming therefrom
- Socio-economic characteristics of prospective immigrants
- Working conditions at the plants and mines, and
- Numbers of people leaving area because of social and economic dislocation

There are indications that a limited labor pool exists within the principal impact areas. Therefore, with extensive coal development, a large number of workers may be induced to migrate into the area, reversing the historic trend of net out-migration. Although the level of migration depends upon the magnitude of development, which varies greatly between CDP's, a net in-migration could occur prior to 1980 in the principal impact area.

(2) *Spatial distribution.*—Coal development is expected to occur at a significant level in only a few of the counties within the principal impact area. Therefore, impacts may be concentrated in only a few key locations and not spread over the area,

Table V-4.—*Coal-related direct operating employment by CDP for Montana, Wyoming, and North Dakota*

State and CDP	Year 1970	1980	1985	2000
CDP I				
Montana	90	1,266	1,276	1,640
North Dakota	300	1,049	1,058	1,345
Wyoming	450	980	980	1,190
Total	840	3,295	3,314	4,175
CDP II				
Montana	90	1,401	3,831	6,593
North Dakota	300	1,058	3,238	10,002
Wyoming	450	1,110	2,640	4,020
Total	840	3,569	9,709	20,615
CDP III				
Montana	90	3,757	8,646	17,076
North Dakota	300	5,282	7,600	21,793
Wyoming	450	1,110	7,130	13,910
Total	840	10,149	23,376	52,779

Table V-5.—*Agricultural employment projections for Montana, North Dakota, and Wyoming (principal impact areas)*

State	1980	1985	2000
Montana	3,330	2,870	2,158
North Dakota	21,807	18,434	14,713
Wyoming	3,510	3,400	3,150
Total	28,647	24,704	20,021

however, this depends to a large degree on the settlement pattern of the migrants.

The most obvious example of this occurs in Wyoming. Under CDP III in year 2000, Campbell County is projected to experience an increase in population of about 64,000, or nearly 800 percent. During the same period, historic trends indicate Niobrara County, a neighbor to the southeast, will experience a decline in population of about 14 percent.

The isolation of some of the plant and mine locations from urban centers coupled with their ultimate size raises the possibility of new town developments. Commuting could pose a problem in coal development areas like those envisioned in Wyoming where plant and mine sites are located in excess of 40 miles from Gillette, the only urban area in the county.

5-3. ***The Principal Impact Communities and Changes Expected from Coal Development.***—Communities within the principal impact areas range from small towns of less than 100 people to a few cities[33], the largest of which is Billings, Montana, with a

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[33] Other large communities in the principal impact area and their 1970 populations include Bismarck (34,703) and Casper (39,361).

Table V-6.—*Total population projections, CDP I, II, III—1980, 1985, 2000 (all units thousands)*

	State totals	Principal impact area			
	1970	1970	1980	1985	2000
CDP I					
Montana	694	123	142	135	157
North Dakota	618	147	163	145	162
Wyoming	332	107	124	128	132
Nebraska[1]	1,483	57	61	62	65
Total	3,127	434	490	470	516
CDP II					
Montana	694	123	144	179	187
North Dakota	618	147	163	188	267
Wyoming	332	107	131	145	160
Nebraska[1]	1,483	57	61	62	65
Total	3,127	434	499	574	679
CDP III					
Montana	694	123	180	203	267
North Dakota	618	147	243	217	368
Wyoming	332	107	140	181	239
Nebraska[1]	1,483	57	61	62	65
Total	3,127	434	624	663	939

[1] Identical figures are shown for Nebraska in all profiles because any changes between CDP's are so small that the differences are negligible in rounding.

population of over 61,000. The typical size of towns in the area ranges between 500 and 3,000, with some villages having populations of less than 20. Some villages may only have a post office that serves the immediate farm or ranch community and a service station which may rely greatly on local trade.

Larger towns may have a school, post office, and a small business center usually consisting of only a grocery and hardware store. Residents of these communities are heavily dependent upon the larger trade and service centers, for example, the county seat towns, to satisfy a large portion of their needs.

Communities such as Forsyth, Gillette, and Hazen, which are undergoing growth from coal development, have been capable of providing most of the service needs of the people within their respective area of influence. Services provided include such facilities as churches, a hospital, farm supply businesses, and a daily or weekly newspaper. Additional services include gasoline service stations, eating and drinking establishments, clothing and food stores, repair facilities, movie theaters, and barber shops. A variety of professional services including those of optometrists, dentists, and veterinarians generally has been provided.

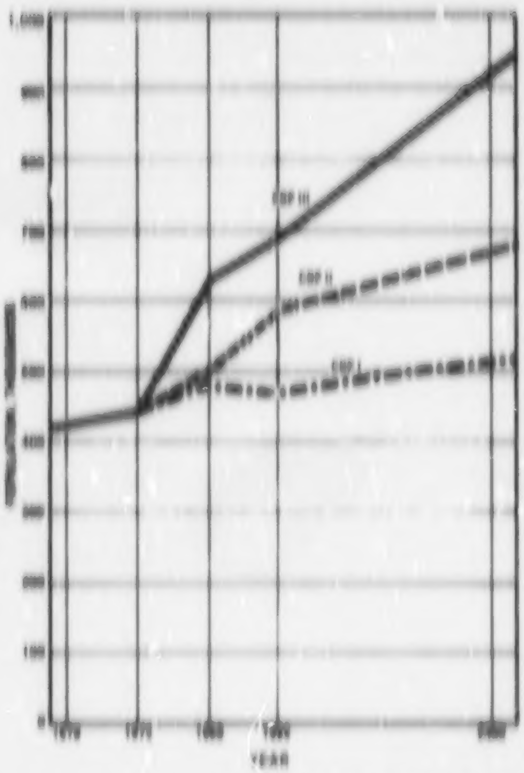

Figure V-4. Anticipated population in the study area for each CEP.

Many services are provided by nonprofit organizations, such as hospitals, social welfare services such as charity, counseling, religious instruction, citizen action, Junior Chamber of Commerce, youth groups, and other groups.

Local governmental services provided include police and fire protection, education and welfare, sanitation, sewage, as well as parks and recreation facilities.

The large urban centers like Billings, Rapid City, Casper, and Bismarck offer a wide range of goods and services and act as wholesale suppliers to the smaller trade centers.

To finance their public service systems, the communities rely principally upon the property tax and user fees which are levied and collected by the local governments. Floating revenue bonds is one common method to finance new public facilities, but this method is generally reserved for the larger cities. A small amount of revenue accrues to the local governments in the form of reapportioned State tax revenues, but these are generally small and vary considerably with the type of tax levied and the individual State tax structure. In addition, revenue-sharing is a new source of revenues for local governments—two-thirds of a State's revenue-sharing allocation is apportioned to units of local governments. Revenue-sharing funds provide a minimum amount of tax relief and support for local government.

As opposed to the rather limited type of revenue sources available to county and city governments, State governments have a variety of revenue sources. Taxes provide the largest share of State revenues, some of which are reapportioned back to local levels of government. The types of taxes and the levels of government to which they are distributed are presented in table V-7.

State revenues are also derived from State and Federal leasing and royalty payments, Federal assistance programs (including revenue-sharing), and Federal grants.

In Wyoming, the royalties paid to the State from production of minerals on State lands go to the permanent fund, while Federal mineral royalties are used only for roads and schools. In Montana, the State share of Federal leasing and royalty revenues is divided equally between the highway and school fund, while State leasing and royalty revenues go to the State school trust. In North Dakota, both State and Federal leasing and royalty revenues accrue to the State's school fund.

c. Labor supply.—A serious question raised by some analysts has been whether the supply of labor will, even with in-migration, be sufficient to fill total demand. It can be argued, for example, that coal-related employment will pay wages higher than the prevailing wages in other sectors. Labor could be bid away from other sectors by coal-energy related developments. This will be particularly critical to the agricultural and service sectors of the economy. Traditionally, the agriculture and service sectors have not paid the level of wages that energy companies anticipate paying. It may be difficult for non-energy-related activities to compete in the future labor market. Substantial substitution of capital for labor may be necessary in these sectors. It must

Table V-7.—*Type of taxes and levels of Government to which the revenues accrue**

	State general fund	County general fund	School equalization or district fund	Long-range building fund	Other
Montana					
Strip coal mine tax	X	X			
State personal income	X		X	X	
Electric energy	X				
Corporation license tax	X		X	X	
Property tax (includes net proceeds)	X	X	X		
Resource indemnity tax†					X
North Dakota					
State corporate income	X				
State personal income	X				
Business and corporation privilege	X				
Sales	X				
Property	X	X	X		
Wyoming					
Severance	X				
Sales-service-use	X				
Conservation	X	X			
Property**					

*Information for South Dakota and Nebraska was not included in the work group analyses.

**Revenues from this tax are divided between the local governments based on their mill levy, e.g., Foundation Program Fund, county tax fund, special district fund, and school tax fund.

†The Montana Resource Indemnity Trust Tax is levied on all mineral resources. The annual income may be legislatively appropriated to deal with local problems related to mineral development.

be stressed that further empirical research is needed to properly assess labor force characteristics and the labor markets. Labor shortages, at least in the short run, do appear to be a reasonable possibility if large-scale coal-energy development does take place.

b. *Population.*—Over recent years, most of the rural areas of the NGP have experienced a decline in population. Despite the population decline in rural areas, there was growth in the larger cities and in those communities that are closely tied to energy development. For instance, during the 10-year period between 1960-70, Gillette, Wyoming, experienced a population increase of over 100 percent; Lame Deer-Ashland, Montana, had a population increase exceeding 27 percent, while Stanton and Center in North Dakota had population increases of over 26 and 30 percent, respectively. Despite these impressive growth rates, the absolute increases were not large.

Although population growth is occurring in some areas[57] population densities are still quite low in the principal impact area as a whole. In 1970, the area averaged about seven persons[58] per square mile compared to the national average of 57.

While many communities within the NGP will be impacted by increases in population resulting from coal development, most of the immediate impact is likely to occur in local communities where the plants will be located or where employees reside. Communities like Gillette and Sheridan in Wyoming; Forsyth, Hardin, Colstrip, and Lame Deer in Montana, and Beulah and Hazen in North Dakota all will be affected by coal development. Table V-8 presents the projected population that would occur in these selected communities as a result of alternative levels of coal development. Presently, both Sheridan and Gillette in the Wyoming impact area are regionally important service centers. If CDP III occurs, Sheridan could become not only a major residential center for energy developments in adjacent areas of Wyoming, but Montana as well, while Gillette has the potential of becoming the dominant wholesale, transportation, and service center for the entire Powder River Basin area.

c. *Institutional and Community Services.*—The communities impacted by coal development are expected to experience a rapid growth in demand for services. None of the services in any of the counties that will be directly affected by construction of gasification plants are capable of handling an increased population without major adjustments. The type of adjustment, however, may not be as important as the rate of adjustment, and many communities may find it difficult to adjust rapidly. It is likely that the smaller communities will be impacted the most, since their ability to absorb growth and finance needed services is more limited than the larger communities.

Services provided by nonprofit organizations, including critical medical care, may be strained by rapid population increases. These areas have had a difficult time attracting and maintaining medical programs in the past, and rapid development and growth will aggravate the situation.

Publicly provided services such as education and municipal water services all require large capital outlays and long lead times to expand. The demand for education is instant upon arrival of workers' school-age children and presents one of the major problems the communities will face in coping with a rapid influx in population. However, if only limited coal-energy development occurs, some communities may have the capacity to handle small increases in the demand for education, medical, and other public services. If not, the communities will have to furnish temporary structures and facilities to handle the rapid influx and these temporary solutions may be totally inadequate in terms of quality of service provided.

A number of public services are financed largely through property taxes, but many construction workers may own little property and will leave before the industrial plant they are building is on the tax rolls. Although there will be lags in tax revenues, construction workers will be paying State sales tax and State income taxes (Montana has no sales tax) (Wyoming does not have a State income tax) which are redistributed in part to the counties. Redistribution of revenues will be one key to alleviating financial problems in the communities impacted by coal-energy development.

During the construction phase of development, school enrollment will fluctuate greatly in the affected communities. More stable enrollment can be expected during the operational phase. Schools built to serve construction-related families can be used to serve the families of operational personnel during the later development stages and at a time when revenues will be more readily available to help finance needed facilities. However, because the construction work force will be considerably larger than the operating work force, flexibility will be needed in planning for expansion of public facilities.

In order to visualize coal-related educational needs in the impacted communities, the

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[57] This is based on the census definition where communities are considered urban if their populations are over 2,500.

[58] This compares to a regional density of 4.4 persons/square mile as described in the Land Resources Section.

Table V-8.—*Population projections for selected communities CDP I, II, III—1980, 1985, 2000*

Town	CDP	1970	1980[1]	1985[1]	2000[1]
		All in thousands			
North Dakota[2]					
Beulah	I	1	3	2	3
	II		3	5	9
	III		7	13	23
Hazen	I	1	2	2	3
	II		2	5	9
	III		8	13	23
Montana[3]					
Hardin	I	3	3	3	3
	II		3	3	8
	III		3	8	23
Forsyth	I	2	3	3	3
	II		3	4	4
	III		4	5	6
Colstrip	I	0.4	3	3	3
	II		3	6	6
	III		6	10	13
Lame Deer	I	1	1	1	1
	II		1	1	1
	III		1	6	6
Wyoming[4]					
Gillette	I	7	12	12	13
	II		14	19	21
	III		17	37	58
Sheridan	I	11	13	15	15
	II		16	23	31
	III		19	32	48

[1] Estimates represent an incremental increase over the 1970 level of population. The increase represents only the population associated with coal development as specified in the CDP's. Population increases that may be added by other activities have not been estimated.

[2] Assumes that 45 percent of the population increase in Mercer County occurs in Beulah and 45 percent of the population increase occurs in Hazen.

[3] Assumes total population increase from Sarpy Creek developments occurs in Hardin. Assumes 25 percent of Colstrip area development resides in Forsyth and 75 percent in Colstrip. Assumes 100 percent of Ashland area development population resides in Lame Deer.

[4] Assumes 80 percent of Campbell County development population resides in Gillette. Assumes 70 percent of population related to developments in Southern Big Horn County, Montana, resides in Sheridan.

number of students that may be added to existing enrollment and the associated facility cost is provided in table V-9. These estimates reflect requirements associated with the operational phase of development only and assume the majority of the workers will reside in the immediate area.

In CDP I, impacts will be localized in communities near the plant and mine sites and in many areas existing capacity could be expanded to handle the anticipated growth.

The population increases projected for CDP II and III, however, are great enough so that even the larger towns located near the development will be affected. If the later stages of development in these higher coal development profiles occur, a whole set of new institutions would be required since the schools, police and fire protection services, and civic organizations would be so large that they would have to adjust. In other words, scaling has an upper limit where a change in kind as well as size will occur. This could bring about serious fiscal problems in those communities that do not have the physical capacity to handle an increasing population.

For example, in CDP II, Campbell County and Gillette are expected to be the most affected area during the early stages of development, but Sheridan County will be more affected in later years. Assuming that most of the increased school enrollment in Campbell County occurs in Gillette, the enrollment would increase by approximately 2,100 in 1980, and increase an additional 2,200 during the 1980-2000 period. Capital cost for providing the necessary facilities during the 30-year period would be $32,400,000. Expenditures for teacher salaries were not estimated, but would probably be significant. Sheridan County enrollment would increase by 1,300 to 1980 and have a total enrollment of 11,600 in the year 2000. This represents nearly a 250-percent increase in 30 years. Total cost of providing the necessary facilities would be $47,500,000.

If CDP III were to occur, Gillette and Campbell County would be one of the most affected areas throughout the development period. Approximately 2,800 new students would be added to the enrollment by 1980, nearly double the 1970 enrollment. By 2000, enrollment would be in excess of 20,000 students. The estimated capital costs associated with providing facilities at the CDP III level would be $12,900,000 to 1980 and total $117,100,000 during the 30-year period to 2000. Sheridan, Mercer, and Rosebud Counties would be similarly affected, but to different degrees.

Financing streets and highways will present problems for the community and county governments in the impact area. In order to place some perspective on the magnitude of projected growth of needed new roads and streets in the impact area, table V-10 presents a "ball-park" estimate of future needs. While no high degree of accuracy is possible in such an analysis, the data do show that the cost of additional new highways to accommodate the projected populations could be substantial. Data are presented separately for arterials and collector streets which might logically be expected to be a public expense and for local streets where the initial cost is usually borne by the land developer. The data show that the cost of expanded or new community streets could exceed the cost of expanded educational facilities as shown in table V-9.

No data regarding governmental expenditures for the principal impact communities were available.[59] Government expenditures constitute another area warranting increased research attention. It is clear, however, as population increases, stress will be placed upon existing service facilities and expenditures for facility expansion will be required. This will be particularly true for the later stages of development projected in CDP II and III.

d. *Housing.*—In many NGP communities, housing is already in short supply, particularly in towns like Lame Deer, Gillette, Colstrip, Beulah, and Hazen, which have felt or are beginning to feel the impact from energy development. Mobile homes are meeting the needs of many of the people and relieving the housing shortage to some extent. This is most evident in Gillette, where in 1973 about 35 percent of the town's 2,000 housing units were

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[59] Although no governmental expenditure data were available from the communities, FY 1974 budgets for the six county area where the communities are located were as follows: Bighorn ($1.6 million), Rosebud ($3.3 million), Mercer ($1.3 million), Oliver ($0.5 million), Campbell ($4.4 million), and Sheridan ($3.3 million).

Table V-9.—*Number of schoolage children and associated capital costs required to provide necessary facilities resulting from the operational phase of coal development—Selected communities—CDP II, III—1980, 1985, 2000*

County	1970 enrollment	CDP	Projected[1] enrollment 1980	Costs[2] millions of dollars 1970-1980	Projected enrollment 1985	Costs millions of dollars 1980-1985	Projected enrollment 2000	Costs millions of dollars 1985-2000
Bighorn, Mont.	3,119	II	3,280	0.5	3,660	6.5	5,070	6.4
		III	3,300	0.5	4,120	6.4	9,560	25.7
Rosebud, Mont.	1,862	II	2,590	0.9	4,060	9.0	5,970	9.0
		III	3,260	15.5	8,470	15.5	11,320	26.9
Mercer, N. Dak.	1,742	II	2,140	2.6	3,760	10.2	6,580	20.6
		III	3,410	15.4	8,700	30.8	14,230	56.6
Campbell, Wyo.	3,897	II	5,940	9.6	7,310	15.4	8,180	18.0
		III	6,740	12.9	13,210	38.6	20,220	65.6
Sheridan, Wyo.	4,706	II	6,000	6.4	8,680	15.4	11,680	25.7
		III	6,900	20.3	11,280	27.0	16,660	47.6

[1] Enrollments projected by Center for Interdisciplinary Studies, Montana State University.

[2] Cost estimates developed by the Bureau of Reclamation. Costs represent capital facilities expenditures to provide for increased enrollments.

Table V-10.–*Perspective of future needs for new roads and streets*

	CDP	Percent increase 1970-1990			Needed new road and street mileage by 1990[4]	Estimated cost for new streets (millions) 1974 prices		
		Population[1]	Vehicle miles of travel[2]	Mileage[3]		Arterials and collectors[5]	Local streets[6]	Total
Beulah,	II	500	798	667	32	9.7	4.8	14.5
N. Dak.	III	1,450	2,363	1,560	75	22.6	11.2	33.8
Hazen,	II	500	798	667	32	9.7	4.8	14.5
N. Dak	III	1,450	2,363	1,560	75	22.6	11.2	33.8
Hardin,	II	42	110	83	12	3.5	1.8	5.3
Mont.	III	292	518	322	46	13.9	6.9	20.8
Forsyth,	II	100	199	155	15	4.5	2.2	6.7
Mont.	III	163	292	235	23	6.9	3.4	10.3
Colstrip,	II	1,400	2,194	1,837	35	10.5	5.3	15.8
Mont.	III	2,587	4,267	2,811	53	16.0	8.0	24.0
Lame Deer,	II	0	50	27	1	0.4	0.2	0.6
Mont.	III	500	798	667	32	9.7	4.8	14.5
Gillette,	II	179	341	197	67	20.1	10.0	30.1
Wyo.	III	504	1,073	585	197	59.4	29.6	89.0
Sheridan,	II	127	196	145	76	22.9	11.4	34.3
Wyo.	III	227	424	274	144	43.4	21.6	65.0
Total	II	172	286	213	270	81	41	122
	III	442	782	510	645	195	97	292

[1] Based on data from table V-8 of NGPRP draft report.

[2] Based on VMT/person data from 1968 and 1990 National Functional Classification Studies for cities in FHWA Region 8 of similar populations.

[3] Based on miles/person data from same source as note 2.

[4] Same as note 3.

[5] Source in note 2 indicates 30.8 percent of mileage is arterial or collector. Costs based on cost/mile for new location construction from 1970-1990 National Highway Needs Study for small urban facilities in that area of country. Cost updated from 1969 to 1974.

[6] Source the same as for note 5.

mobile homes, and the number is rapidly increasing. The city planned for the development of 380 new trailer homes during 1974. The communities involved can circumvent the trailer home park problems particularly concerning lower property assessment by implementing zoning laws or by changing the status of mobile homes for taxation purposes.

In the future mobile homes will probably continue to play a major role in meeting the housing demands of impacted communities, particularly for workers who are present for short periods of time. This will be most evident in the early years of development when a large percentage of new housing may be composed of mobile homes. As development phases into maturity, however, the percentage of mobile homes can be expected to decrease and the number of permanent dwellings substantially increase. Even if 70 percent of new housing is mobile homes, a significant demand will be placed on the local construction industry to meet new home construction needs; for example, in Gillette the number of housing units would increase from 2,000 in 1970 to 4,000 by 1980, and 22,000 by the year 2000—CDP III. This represents an annual increase of 900 homes per year over the 20-year period. If 70 percent of these units are comprised of mobile homes, approximately 1,200 permanent housing units (including apartment-type structures) would be required by 1980 and another 330 annually during the next 20 years. This would place a tremendous demand on the local home-building industry in Gillette, which in 1973 had about 40 new housing starts.

(1) *Operational phase.*—Housing needs of the various communities are summarized in table V-11. As the estimates indicate, housing requirements will vary considerably by community and CDP. Housing needs for CDP I were not evaluated in depth; however, by the year 2000 a total of 2,000 additional housing units would be required to meet the demand in Gillette, and 1,000 additional units in Colstrip for CDP I. Other communities will be impacted but perhaps to a lesser degree.

Of the communities identified in the housing study, Lame Deer, Hardin, and Forsyth would be the communities least affected by coal development in CDP II. The CDP III level of development, however, would require substantial expansion in all communities, generally after 1985. In CDP II, Lame Deer would not require additional housing in any time frame, but under assumptions of CDP III, 2,000 units would be required by 1985. Because of the development pattern projected in CDP II, Hardin would not require coal-related housing until the year 2000. (This assumption was based on workers living close to mines and conversion facilities. Recent experience has shown that workers are commuting over 200 miles and demand for housing in Hardin is high.) Substantial expansion would occur in CDP III—a total of 9,000 units in the 15-year period between 1985 and the year 2000.

Forsyth, a community which has experienced the expansion and contraction of the oil industry in the past decade, would be required to provide 1,000 additional housing units by 1985 with no further expansion anticipated through the year 2000—CDP II. In CDP III, 2,000 units would be required, 1,000 by 1980, and another 1,000 units by the year 2000.

Sheridan, Wyoming, would require the greatest number of housing units in CDP II with about 9,000 new units required between 1980 and 2000. Gillette, Wyoming, would require the greatest number in CDP III, requiring about 22,000 housing units during the same 20-year period.

(2) *Construction phase.*—Although the total housing needs associated with the construction phase of development have not been estimated, the increase in housing resulting from construction of a single gasification or power plant has been determined (fig. V-5). These estimates reflect a 3- and 5-year construction schedule for a gasification and power plant, respectively.

As figure V-5 suggests, the housing needs of construction workers will fluctuate considerably and will significantly impact the communities affected by development.

Table V-11.—*Coal-induced housing needs for selected communities—Operational phase development*[1] *(all in thousands)*

Town	CDP	1970	1980	1985	2000
Beulah	II	0.5	0	2	1
	III		3	2	5
Hazen	II	0.5	0	2	1
	III		3	2	5
Hardin	II	1	0	0	2
	III		0	2	7
Forsyth	II		0	1	0
	III		1	0	1
Colstrip	II	0.4	1	1	0
	III		2	3	1
Lame Deer	II	0.5	0	0	0
	III		0	2	0
Gillette	[illegible]	2	3	2	1
	[illegible]		4	9	9
Sheridan	II	4	2	3	4
	III		3	6	7

[1] Not included are present and projected needs associated with other factors.

In fact, the demands will be even greater than those anticipated for the operational phase of development. The peak construction year could require at a minimum three to four times the number of permanent employees needed in the operational phase if each worker constitutes one housing need and thus create substantially greater housing demands, although of relatively short duration.

e. *Revenue*.—The ability of local governments to provide increased levels of service as well as new services may well become one of the most critical problems associated with coal development in the NGP. Conceivably education and highways may be the most visibly impacted service areas.

Securing sufficient capital to expand classrooms and construct new school facilities and highways could be a very difficult obstacle to overcome in most instances. Complicating the above situation is the potential of very high short-term demand for these services during the construction phase of coal development. The short-term demands potentially could become substantial in CDP II and even greater under CDP III levels.

Revenue-service demand lags, capital shortages, jurisdictional disputes, and a rapidly fluctuating population base have the potential for severely testing the structure of local government and nongovernmental services. Additional study regarding the aforementioned areas as well as site specific development plans is needed before any firm cost estimates can be made and before any firm strategy to remedy

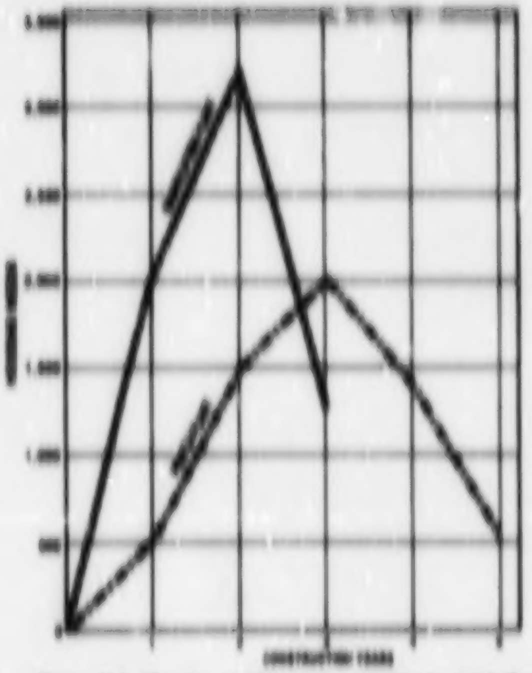

Figure V-3. Housing requirements necessary to meet the needs of construction workers associated with a single gasification plant and powerplant. Assumes each construction worker needs one housing unit.

these problems is undertaken.

(1) *Tax revenues.*—Funds to meet budget requirements will be one of the most critical problems the communities will face in their efforts to cope with rapid development. This will be most evident in the construction phase of development when coal-derived revenues will not be available for funding purposes. Providing that the State governments can effectively and expeditiously reapportion these revenues to local governments, prospects for relieving financial strains would be improved. Within a six-county area[10] where revenues were estimated (assuming current tax rates and methods of taxation), new revenues generated annually in CDP I would be $44 million in 1980 and approximately $86 million in the year 2000. In CDP II annual revenues would be $47 million in 1980 and $172 million by the year 2000. Tax revenues in CDP III would be substantially greater: $76 million in 1980 and $373 million by 2000.

The primary levels of government that will benefit from these new tax revenues include the county fund, local school district fund, and the State general fund. The State general fund and local school district fund are expected to benefit the most, claiming approximately 75 percent of all tax revenues. Other levels of government that will benefit, albeit to a lesser extent, include the county fund, school equalization fund, long-range building fund, foundation program fund, and the special district fund.

(2) *Coal royalty revenues.*—Coal royalties,[11] although substantially smaller than tax revenues, will nevertheless be important. Thirty-seven and one-half percent of the coal royalty revenues are returned to the States, in which the royalties were generated. These funds can be spent only on public education or public roads. The revenues derived from coal royalties are not necessarily reapportioned to the counties where the coal was extracted.

It is estimated that 85 percent of all coal royalty revenues accruing to the State would be generated within the six-county area.

Based upon present methods of determining coal royalties, it is anticipated that annual revenues in CDP I would total approximately $14 million in 1980 and increase to slightly more than $20 million in the year 2000. In CDP II, revenues would range from $17 million in 1980 to $42 million in year 2000. And in CDP III, 1980 revenues would approach $22 million annually, rising to $132 million by the year 2000.

(3) *Summary.*—The prospects for financing coal-energy induced service delivery systems would be considerably improved, providing that the tax revenues and coal royalties be reapportioned efficiently and effectively to the heavily impacted areas by the States. At present, Federal statutes restrict the States' flexibility in distributing royalties from Federal coal and royalties from coal mined

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[10] Six-county area includes Rosebud, Bighorn, Montana; Sheridan, Campbell, Wyoming; Oliver, Mercer, North Dakota.

[11] Coal royalty revenues will be divided almost evenly between the State and Federal governments, with the Federal royalty adjusted to account for the 37.5-percent amount that is required by the Mineral Leasing Act to be returned to the States. These revenues were estimated on the basis of a State and Federal royalty rate of $0.11 per ton.

from State school lands. Determining methods to handle the local financial problems resulting from coal-energy development is a research and legislative issue needing immediate action.

Total revenues generated by year 2000 in CDP III may exceed one-half billion dollars annually. Sufficient tax revenues, however, may not be available to meet fund requirements during the construction phase of development and in the first few operating years. Secondary impacts may aggravate the communities' future attempts to reach fiscal equilibrium. For example, secondary or satellite industries could swell population thus increasing public service demands which would be difficult for the communities to meet. The situation could be altered by State legislation or by State or Federal impact funds. This time lag between revenue generation and service needs may place a severe budget strain on communities impacted by coal development. This problem is occurring in some NGP communities today.

5-4. *Impact on Indians as a Result of Coal Development.*—The NGP five-state study area encompasses all or parts of 23 Indian reservations. These reservations contain Indian-owned land ranging from about 20,000 acres to millions of acres and have Indian populations ranging from a few hundred to over 11,000. The reservations, in total, contain over 13 million acres of land, covering more than 20,000 square miles, an area considerably larger than many States. This land provides a resource and cultural base for over 80,000 tribal members.

There is a great amount of institutional complexity regarding the Native Americans in relation to the rest of society in the NGP. Indian reservations are independent political entities, each having its own political structure and legal codes. The States in which they are located have little if any jurisdiction within the reservation boundaries. The reservations represent a great diversity of subethnic groups, and differ significantly in their approach to socio-economic situations. They have historically been socio-economic as well as geographic islands in a region already isolated by great distances.

Services which are normally the responsibility of local or State government in a non-Indian community are performed in a cooperative effort between the various tribes, the Department of Interior BIA (Bureau of Indian Affairs), and other Federal and State agencies. This includes a United States trust responsibility in the performance or assistance in the development, use, control, and protection of Indian lands and land-related resources as well as the construction, maintenance, and operation of irrigation systems and the development of recreational services and areas. Socio-economic services such as educational, health, and credit facilities are derived from BIA and the Public Health Service, as well as from standard Government and private sources.

On some reservations, over half of the Indian land is owned by the tribal entity. On others, a very large majority is in individual Indian allotments. The amount of Indian-owned lands decreased steadily during the first 65 years of this century. This occurred through cession to the Federal Government or by sale to non-Indian owners. During the past three decades, several tribes on the Missouri River have lost considerable amounts of land to large main-stem reservoirs. This erosion of land ownership has been minimized in recent years, and most of the tribes are now taking specific steps to consolidated ownership, to acquire key tracts of land, and to further minimize land attrition by purchasing individual allotments that otherwise would be sold to non-Indians.

The land on the Indian reservations ranges from high forested mountain areas in Montana to semiarid grasslands typified by several South Dakota reservations, as well as fertile irrigated river bottom valleys. Like non-Indian lands, some areas are underlaid by the huge coal reserves of the Fort Union Formation. Special attention is being given to the development potential and jurisdictional aspects of the Indian water and other mineral resources in the NGP Region. The specific identification and quantification of these resources and rights is a major effort of the Native American Natural Resources Federation of the Northern Great

Plains. A report by this Federation entitled "Declaration of Indian Rights to the Natural Resources in the Northern Great Plains States" is appended to this report.

a. *The Six Most Affected Reservations.*—Table V-12 shows the land area and population of the six reservations in Montana and the Dakotas that will feel the major social and economic impact from coal development. These six reservations are home for about 25,000 Indians and encompass over 5.6 million acres—an area larger than New Jersey.

About equal acreages of Indian coal rights lie partly within and partly outside the reservation. These coal reserves amount to billions of tons.

b. *Population.*—All six reservations have experienced a significant population increase in the last 10 years (table V-13). The Indian population increase contrasts sharply with the overall population changes that occurred in the States where the six reservations are located.

c. *Age.*—The reservation residents are quite young; nearly half of them are under 16 and nearly two-thirds are under 25 years of age. Separate analysis of the 1970 census shows that about 40 percent of the population in both Montana and South Dakota was under 19 years of age. The Indian population of the six reservations in this category ranges from 53 percent on the Crow Reservation to about 62 percent on the Fort Peck Reservation.

Table V-12.—*Indian land and residents, by reservation, 1973*

Reservation	State	Indian-owned land (acres)*	Indian resident population
Crow	Montana	1,562,077	4,334
Fort Peck	Montana	961,857	6,202
Northern Cheyenne	Montana	434,420	2,926
Fort Berthold	North Dakota	420,718	2,775
Standing Rock	North Dakota, South Dakota	846,684	4,868
Cheyenne River	South Dakota	1,405,178	4,335
Total		5,630,934	25,440

*Acres include land both on and off the reservation. Source: Bureau of Indian Affairs (1974).

Table V-13.—*Indian population change, 1963-73*

	Population		Percent increase
	1963	1973	
Crow	3,678	4,334	17.8
Fort Peck	3,390	6,202	82.9
Northern Cheyenne	2,166	2,926	35.1
Cheyenne River	3,421	4,335	26.7
Fort Berthold	2,408	2,775	15.2
Standing Rock	4,300	4,868	13.2
Total	19,363	25,440	31.4

Source: Bureau of Indian Affairs (1974).

The high percentage of Indian population in the younger age groups, compared to the relatively low populations in the groups 45 years and older, indicates a considerable potential for an increased Indian labor force. It also contributes to a high degree of dependency, with over half of the total population being either under 16 years of age or over 65 years of age.

d. *Labor Force and Employment.*—All six reservations have higher unemployment rates than the States where they are located. The 1970 unemployment rates reported by the Bureau of Labor Statistics for NGP reservations ranged from 11.6 percent to 29.1 percent. Comparable rates for Montana were 6.3 percent; for North Dakota, 4.6 percent; and for South Dakota, 3.3 percent (table V-14).

Current Indian employment is primarily in agriculture, government, and tourism. The Northern Cheyenne also have a significant number of people employed in logging and milling. These skills provide the primary nucleus for developing the Indian manpower for employment in the coal-related industries. If the Indian labor force is to be employed in coal industries, many of them will need to learn new skills. Many Indian tribal members who have been or are in apprenticeship for trade skills have been grouped into an organization called the Indian Action Team. This assumes that members of the Indian labor force will actually seek employment in coal industries. The high unemployment rates on the reservations indicate that they would.

However, many Indians are concerned about the adverse social and economic changes that coal development may bring and this may influence their decision regarding establishment of strip mines and power and gasification plants on their reservations.

e. *The Indian Family and Income.*—On the six reservations, Indian family size is larger, family income is lower, and a greater percentage of Indian families are in poverty than is found in the population standard of the six States where they are located, or in the U.S. population. These large families and low income are reflected in the percentage of the families having an income below the poverty level as defined by a Federal interagency committee in 1969[11] (table V-15).

f. *Educational Levels.*—Educational levels on the six reservations are significantly lower than those for the total populations of the States in which these reservations are located.

Table V-14.—*Unemployment Rates: North Dakota, South Dakota, and Montana, compared to Indian reservations within their boundaries, 1970*

Area	Percent unemployment
Reservations	
Crow (Montana)	11.6
Fort Peck (Montana)	25.7
Northern Cheyenne (Montana)	11.1
Cheyenne River (South Dakota)	18.4
Standing Rock (North Dakota-South Dakota)	29.1
Fort Berthold (North Dakota)*	—
States	
Montana	5.5
North Dakota	4.6
South Dakota	3.3

*Data for Fort Berthold were not available.

Source: Bureau of Labor Statistics, U.S. Department of Labor.

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[11] Employment Profiles of Selected Low Income Areas, Bureau of Census, Department of Commerce.

Table V-15.—*Family size and income: Indians compared to total population*

Area	Average family size	Median family income	Families with incomes below poverty level
	Persons	Dollars	Percent
Reservations:*			
Crow	6.60	5,260	40.0
Fort Peck	6.54	5,136	46.7
Northern Cheyenne	5.37	5,270	39.8
Cheyenne River	5.99	3,857	54.8
Fort Berthold	6.10	4,800	45.3
Standing Rock	5.38	3,667	58.3
States:†			
Montana	3.58	7,494	10.4
North Dakota	3.72	7,838	12.4
South Dakota	3.66	8,512	14.8
U.S. (all families†)	3.62	9,433	10.7

*Data from Bureau of Indian Affairs (1974).
†Data from 1970 Census of Population.

A brief comparison from U.S. census data for the Crow and Standing Rock Reservations shows the median educational level of Indians over 25 years is almost 3 years less than non-Indian NGP residents. The Indians have been deprived of many of the social and economic opportunities for advancement that have been taken for granted by other residents of the NGP. This is in part directly related to the social, economic, political, and cultural isolation of the reservations.

g. *Anticipated Reservation Coal Development.*—The Standing Rock and Cheyenne River Reservations have combined coal reserves estimated at some 100 million tons. However, commercial exploitation is considered marginal, and mining companies have thus far shown little serious interest in development.

Fort Berthold Reservation is reported to have between 4 and 20 billion tons of measured and indicated lignite reserves, much of which is commercially recoverable under present technology. However, members of the three affiliated tribes have expressed great concern about the cultural and environmental issues accompanying coal development and have imposed an indefinite moratorium on leasing and other mineral activity.

The Fort Peck Reservation in eastern Montana has strippable lignite reserves estimated at several billion tons. However, coal developers have shown little interest in them, and no leasing or prospecting activities are currently underway.

The Northern Cheyenne Reservation also has huge coal reserves, estimated in excess of 5 billion tons of strippable deposits. However, tribal leaders and members are presently discouraging any development activity until the social and environmental effects of coal development are more fully understood. Testimony presented by the Northern Cheyenne Landowners Association at hearings regarding coal development conducted by U.S. Senator Lee Metcalf from Montana in April 1974 illustrates their concern:

"The imminence of strip mining on the Northern Cheyenne Indian Reservation is bringing about a questionable future for the resources and Indian lands as well as the lives of the people exposed to it. The magnitude, nature, and rapidity with which this development will be brought upon the Cheyenne can only be felt as modern day genocide."

The Crow Reservation is the only one of the six where coal development is imminent. There is a diversity of opinion among members of the tribe as to the desirability of coal development on the reservation proper. Public hearings held at the Crow Agency, Montana, in November 1973 produced testimony by tribal members both for and against coal development.

Arrangements have already been made with Westmoreland Resources to mine at least 77 million tons of Crow-owned coal on Sarpy Creek in the ceded area which lies immediately north of the present boundaries of the Crow Reservation. Just under 1.5 million tons were produced in 1974 with 1975 production projected at 4 million tons. A final environmental impact statement relating to that mining operation has been prepared and filed.

In addition, the Crows have either prospecting permits or leases with AMAX, Gulf Minerals Resources Company, Peabody Coal Company, and Shell Oil Company. Explorations by these companies indicate a total of 4 to 4.5 billion tons of coal considered strippable under present economic and technical conditions.

Significant employment opportunities for Crow Indians may become available in coal-related industries on or adjacent to the Crow Reservation. If only two or three strip mines are operated, and if they seek work in the mines, the work force could conceivably be mostly Crows since they are assured preferential hiring rights. However, a significantly higher level of development may require very high non-Indian employment. This implies the possibility that the Indians might become a minority on their own reservation unless specific residential controls are exercised. In an attempt to alleviate this problem, the Crows have been assured preferential hiring status in the coal industry.

The potential impact of coal development on the culture and lifestyle of the different NGP Indian tribes has not been adequately explored. A complete knowledge of the culture and lifestyle of the Indian is a prerequisite of such an impact study. The only people having such knowledge are the tribal members; therefore it is logical to assume that they should be responsible for determining the potential beneficial or adverse impacts coal development may have on their culture and lifestyle. Some tribes have been attempting to develop the capability of making these studies and communicating the results to non-Indians. To date, this effort has been only marginally successful, primarily because of a lack of sufficient local technical expertise and external support. In recent months, the Native American Natural Resources Development Federation of the Northern Great Plains has been organized by the NGP tribes to begin to address in a cooperative way the mutual problems the tribes are confronted with. A high priority need of this group is the description of their natural and cultural resource base and the protection of their water rights. If this group is successful, it may provide answers to many of the questions related to the issues raised in this section of the report.

5-5. Agriculture—The Present Setting.—Within the agriculture study area, which includes portions of the four States of Wyoming, Montana, North Dakota, and South Dakota, there are approximately 91 million acres of land, of which approximately 24 million acres are classified as cropland and 70 percent or 63 million acres is in pasture or rangeland. Of the cropland, 97 percent or 23 million acres is nonirrigated and 694,000 acres or the remaining 3 percent is under irrigation. Presented in table V-16 is a summary of total land use in the study area.

Within the study area there are 37,920 farms and ranches ranging in size from an average of 815 acres in Ward County, North Dakota, to 11,105 acres in Natrona County, Wyoming. The farms and ranches average approximately

Table V-16.—*Land use summary—NGP study area by state—In millions of acres**

Total land area acres	Cropland				Pasture and rangeland		Forest and woodland		Urban	
	Million irrigated acres	Percent of total	Million non-irrigated acres	Percent of total	Million acres	Percent of total	Million acres	Percent of total	Million acres	Percent of total
Montana 34,625.9	361.4	1.0	5,923.1	17.1	26,419.9	76.3	1,649.2	4.8	272.2	.8
North Dakota 25,840.2	55.1	.2	14,650.3	56.7	10,434.3	40.4	154.4	.6	546.0	2.1
South Dakota 11,556.1	64.6	.5	1,757.4	15.2	9,548.4	82.6	154.6	1.3	31.1	.3
Wyoming 18,858.9	212.4	1.1	484.0	2.6	16,140.1	85.6	1,716.8	9.1	305.6	1.6
NGPRP study area 90,881.0	693.5	.8	22,814.8	25.1	62,542.7	68.8	3,675.0	4.0	1,154.9	1.3

*The 90,881-million-acre study area for the agricultural analysis varied slightly from the 91.5 million acres Surface Resources Work Group study area.

(Overall Source: U.S. Census of Agriculture, 1969, plus published and unpublished Federal agency data. Land use statistics may exceed State acreage totals due to the grazing of forest lands.)

2,400 acres in size, with the average size of a farm in: Montana—3,771 acres; North Dakota—1,204 acres; South Dakota—3,598 acres; and Wyoming—6,329 acres.

As of January 1, 1972, nearly 3.75 million head of cattle and calves stocked the farms and ranches, sheep and lambs numbered about 2 million, while hogs totaled slightly more than 300,000.

Wheat is the principal crop grown in the study area, and occupies about 30 percent of the total cropland under production. In 1971, slightly more than 130 million bushels of wheat averaging 20 bushels/acre were produced on approximately 6.5 million acres.

Other major crops produced in the study area include barley, flax, oats, corn, alfalfa, and sugar beets. Smaller acreages of potatoes, soybeans, sorghum, rye, and beans are also produced within the area, together with poultry and dairy products.

5-6. *Agricultural Impact Assessment*.—Coal development will affect NGP agriculture in three principal resource areas—labor, water, and land. The method of mining, the level of development, and the method and location of coal utilization will determine to what extent agriculture will be affected.

a. *Labor*.—Strip mining and construction of energy conversion facilities will compete directly with agriculture for labor resources as both industries place a premium on men in their physical prime who are accustomed to working with machinery and to working long hours outdoors.

Operators of small farms who are underemployed in their farm businesses may provide a limited labor source for industry. It is expected that some of these operators may take advantage of the new off-farm job opportunities that industry provides and shift themselves and their families into higher levels of income while operating their farms on a part-time basis. Others may leave agriculture entirely, taking advantage of the higher income levels that coal-related industry will provide.

Dual employment is a possibility in some areas of the NGP. Two distinct types of agriculture are practiced in the Fort Union-Powder River region. Dryland farming dominates in the coal areas of North Dakota, whereas ranching is the dominant agriculture activity in the coal areas of Wyoming and Montana. Increased mechanization and a reduction in the farm labor force is possible in the farming sector; however, ranching is not very amenable to mechanization. Nevertheless, during certain times of the year both agricultural activities require additional help, and this may not be available due to change of occupation by the underemployed and the area's youth brought about by the higher paying jobs in the energy industry. Operators who are fully employed with adequate income from farming and ranching and who do not hire much extra labor will be affected least by labor market changes. They likely will not be attracted to off-farm work and higher wages for hired labor will have little effect on their operation. However, those operating large farms and ranches and hiring large amounts of labor will probably be forced to make adjustments in their operations particularly at the higher levels of coal production as envisioned under CDP II and III. These adjustments, which may or may not be considered desirable, may include dropping certain labor-intensive enterprises, adopting labor-saving techniques, and perhaps even reducing the size of their farming operation.

An overview of the effect that coal development will have on the labor resources in the NGP suggest that the supply of labor available to agriculture may be reduced. This may not cause major changes in farm organization in the development area of North Dakota, yet the potential for accelerating the trend towards fewer and larger farm units exists. Other parts of the NGP will experience similar effects. Large ranching enterprises, like those located in some parts of Wyoming and Montana which are based largely on hired labor, may experience difficulty in hiring and retaining capable workers in competition with an expanding coal industry. Competition for labor would be aggravated in CDP II and III. The degree of labor conflicts between agriculture and the coal-related activities cannot accurately be anticipated until more is known about the scheduling of coal development, labor requirements, and in-migration of labor.

b. *Water.*—The amount of water necessary for coal development even at the CDP III rate of development does not necessarily have to compete with water used in existing agriculture production. However, conflict between agriculture and industry over future use of water that is beyond presently established uses and future coal development needs of the area may occur. It should be noted that industry is purchasing farms and ranches and converting the agricultural water right to industrial use. A discussion of this is presented in the Water section, part IV-2.

It has been estimated that more than 3.0 million acre-feet of water is available, with new storage, in the Upper Missouri River Basin to meet future water requirements. Of the 3.0 million acre-feet that could be made available, 800,400 acre-feet is needed for CDP III. The balance, ostensibly, could be used to serve other uses including new irrigation development. Water use in the Yellowstone Basin above the CDP II level of coal development would require additional storage facilities, however, to provide water above that needed for minimum flows.

In 1970, there were about 694,000 acres of land under irrigation in the 63-county study area and little expansion has occurred since that date. With the current deemphasis on new Federal irrigation development, it is not expected that the irrigated base will, within the study area, increase substantially in the near future. Presently, within the Yellowstone River Basin there are no projects which are being studied for new development that would meet federally funded economic justification. There is some potential for new State-assisted and private irrigation development in the Yellowstone River Basin, but that is not expected to exceed 100,000 acres.

North and South Dakota are each planning federally funded projects that will expand their irrigation base, but these projects are outside the study area, and have been previously authorized under different formulation criteria.

c. *Land.*—More land will be removed from agriculture production as more coal is mined. Overall, however, it is not anticipated that industrial disturbances of the land will have a major effect on the area's agriculture productivity.[13]

Under CDP II, for each of the years between 1985 and 2000, there would be approximately 130,000 acres of land displaced.[14] This represents a 242-percent increase from the 38,000 acres assumed to be disturbed in CDP I and 138 percent less than the 309,000 acres would be disturbed if CDP III occurs. The amount of land displaced relative to the total land area of 91 million acres is 0.04 percent in CDP I, 0.14 percent in CDP II, and 0.34 percent in CDP III. Table V-17 summarizes the amount of land that would be disturbed in all study area counties by profile and by time frame.

The plant and mine sites are located almost entirely on rangeland. Therefore, it is not expected that irrigated agriculture will be affected and only a small percentage of the dry cropland in the study area would be disturbed. Table V-18 summarizes the annual displacement of cropland in the study area in terms of production and acreage disturbed, beginning in 1980—CDP III. Only land assumed to be affected under CDP II and CDP III have been projected. Under CDP I, only a minor amount of cropland would be displaced.

The loss in wheat production, which is the principal crop grown in the study area, would be approximately 0.22 percent of the total wheat being produced under CDP II and 0.45 percent under CDP III. Barley and oat production would be affected but only to a relatively minor degree.

The loss in vegetation to support cattle production in the NGP area is minimal. For example, the level of surface mining indicates that a total of approximately 224,000 acres of rangeland would be unavailable for grazing in year 2000. This includes natural grazing lands currently being mined, and that which is in the process of rehabilitation following mining, as well as the acreage more-or-less permanently occupied by mine facilities, transmission lines, and other coal-related uses. At a rate of 3 acres/AUM (animal-unit-month), an equivalent

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[13] Under the assumption that National Ambient Air Quality Standards have been adequately set to protect public health and welfare (including damage to vegetation and animal life) and that these standards will be enforced, no impacts of air pollution on agriculture are anticipated. It should be noted, however, that effects of some trace elements on vegetation are not fully understood and that standards have not been set for these elements.

[14] This represents the total amount of land out of production at any one time.

Table V-17.—*Cumulative agricultural acres displaced as a result of coal development in the Northern Great Plains Study Area CDP I, II, and III**

	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Fixed acres out of production for plant sites, etc. (acres)	4,100	4,100	4,100	25,300	25,300	25,300	60,700	60,700	60,700
Crop and rangeland being disturbed (acres)	19,000	33,500	33,500	65,000	104,300	104,300	148,100	247,900	247,900
Total acres disturbed	23,100	37,600	37,600	90,300	129,600	129,600	208,800	308,600	308,600

*Acres do not correspond directly with total acreages disturbed shown in Part IV as they were based on different assumptions of when mines and plants would begin operation and because allowance was made for being rehabilitated to cropland productivity after 5 years.

Table V-18.—*Cropland and associated production displaced annually between 1980 and 2000—CDP II and III*

CROP	CDP II		CDP III		
	Acres displaced	Production[1] bushels	Acres displaced	production bushels	Value[2] dollars
Wheat	13,807	276,140	28,400	586,000	714,000
Barley	1,205	44,505	2,878	106,500	87,300
Oats	3,866	193,300	7,328	366,400	172,200
	18,878	513,945	38,606	1,058,900	913,500

[1] Based on 1971 average annual yield—wheat 20 bushels/acre; barley 37 bushels/acre; oats 50 bushels/acre.

[2] 1971 weighted average seasonal price for Montana, Wyoming, and North Dakota as follows: Wheat—$1.22/bushel; oats—$1.47/bushel; and barley—$0.82/bushel (more recent values for these commodities would be considerably higher).

of the grazing needs of only 6,200 animal units on a year-long basis would be lost.

Statistical Reporting Service data on 1972 livestock numbers, converted to an animal-unit-basis, indicate a total of 3,178,410 animal-units of cattle, calves, sheep, and lambs in the region. Therefore, the total animal-units displaced by mining activities at the CDP III level of development in year 2000 would be only 0.0019 percent, or less than 2/10 of 1 percent of present livestock numbers in the region. The value of the grazing lost, at a rate of $6/AUM, would total $447,700 in year 2000 (table V-19).

Table V-20 summarizes the number of animal units of grazing that will be affected in the five-county area as compared to the region as a whole. This is followed by table V-21, which summarizes by time frame the amount of grazing land taken out of production and the value foregone as a result of coal development in the five-county primary impact area.

Approximately one-half of the impact to the land in the NGP will be experienced in the five-county area of Rosebud, Bighorn Counties, Montana; Campbell County, Wyoming; and Oliver and Mercer Counties, North Dakota, where most of the mining activities are expected to be located (table V-20). In this five-county area by year 2000—CDP III, 3,200 animal-units of grazing valued at $226,000 are estimated to be displaced by coal development. This represents about 0.92 percent of the total, 342,000 AUM's of grazing in the five-county area.

As indicated here, the impact of coal production on agriculture in the aggregate will be relatively insignificant. The impact from mining, however, will be much more severe on an individual livestock operating unit basis. A single surface mine, with its attendant facilities, could displace a significant portion, or all, of an operating unit. A large mine operation, for instance, could affect several adjacent livestock units and the impact in such cases could be so extensive that the operating unit would cease to exist.

The value of an individual tract or acreage to a livestock operating unit is frequently not based directly upon the productivity of that tract, but that the tract provides forage during a critical period of the year when no other forage is available. It may, therefore, be an essential link in the year-round livestock operation, although it produces a small amount of the year-round forage supply (for example, the spring lambing for a sheep unit or a subirrigated meadow which can be grazed when upland ranges are dry).

Table V-19.—*Total acres of rangeland displaced in study area and value foregone 1980-2000, CDP's I, II, and III*

Item	CDP I			CDP II			CDP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Mined to date	4,500	10,600	34,200	4,700	13,000	70,300	6,800	26,500	157,400
Mining facilities	1,400	1,400	3,200	1,800	8,600	19,000	7,500	21,200	45,500
Permanently out	—	—	—	—	—	—	—	—	17,800
Temporarily out	—	—	—	—	—	—	—	—	72,700
Total Rehabilitation	—	−1,000	−19,700	—	−1,000	−32,500	—	−1,500	−69,500
Net acres out of production	5,900	11,000	17,700	6,500	20,600	56,800	14,300	46,200	223,900
AUM grazing @ 3 ac/AUM*	2,000	3,700	6,000	2,200	6,900	19,000	4,800	15,400	74,600
Total animal units—annual*	200	300	500	200	600	1,600	400	1,300	6,200
Grazing value @ $6.00/AUM	12,000	22,000	35,500	13,000	42,000	113,700	28,700	92,500	447,700

*Total may not be exact due to rounding.

Table V-20. *Total animal units (AU) of grazing in five-county concentrated area and displacement—Year 2000*

Area	Animal units January 1973	Animal units displaced	Percent of present AU's
		All units in thousands	
Campbell County, Wyoming	87,700	1,000	1.08
Bighorn County, Wyoming	98,500	700	0.67
Rosebud County, Montana	79,100	900	1.18
Mercer County, North Dakota	76,700	600	0.78
Oliver County, North Dakota			
Total four sample counties	342,000	3,200	0.92
Region Total	3,178,400	6,300	0.19

Additional factors will have to be taken into consideration. This element will affect grazing values when a portion of a livestock operating unit is diverted to a nongrazing use such as surface mining. The location of the development in relation to other lands and to livestock handling facilities is important. If a mining development was located at the outside edge of a larger grazing unit, it may have little effect other than reducing acreage available for grazing. If, on the other hand, the mining development was located near the center of a livestock ranch, or farm, it could seriously interfere with movement of livestock, fencing and pasture arrangements, livestock water supplies and distribution, animal performance, and in general disrupt the overall farm operation. Ranching and farming, despite outward appearances, is a rather intricate system and loss of grazing lands or lands to cultivate could render a ranch or farm uneconomical. There is no doubt that the harvest of revenues from coal will be greater than the revenues from agriculture, but coal is a one-time harvest.

Secondary impacts from coal development will also affect agriculture. As the population expands, additional land will be needed for streets, schools, homes, and businesses. Other land-related activities and values such as recreation, hunting, and aesthetics will temporarily be foregone and in some instances permanently foregone.

5-7. ***Societal and Cultural Impacts of Coal Development.***—One of the most difficult aspects of development to understand is its effect upon the people who live in the impacted areas, be it the newcomers or oldtimers. Social change is a very complex process and it affects individuals differently as well as the communities in which they reside. The use of the land, be it for agriculture or recreation, is fundamental to the culture and way of life of persons who live in the NGP. The social system and culture of the NGP is dominated by three distinct groups of people: Farmers and ranchers, townspeople, and Indians. The first two groups share one culture, while the Indians have a separate, yet related, culture.

Coal development will accelerate the urbanization process that is occurring in the NGP region. Urbanization is not simply the growth of population, but a process. To understand the impact of coal development on the culture and lifestyle of the NGP residents, an understanding of the process of urbanization and its impact on a rural society is necessary. The term "urbanization" can be described as a process which changes the way people relate to one another. As urbanization

Table V-21.—*Total acres of rangeland displaced in five-county concentrated impact area and value foregone—1980-2000, CIP's I, II, and III*

Item	CIP I			CIP II			CIP III		
	1980	1985	2000	1980	1985	2000	1980	1985	2000
Mined to date	4,500	10,600	34,000	4,600	12,300	55,800	5,700	20,000	110,300
Mining facilities	1,400	1,400	2,900	1,700	6,800	10,900	5,000	16,100	29,000
Permanently out	—	—	—	—	—	—	—	—	8,100
Temporarily out	—	—	—	—	—	—	—	—	19,900
Total rehabilitation	—	−1,000	−19,700	—	−1,000	−27,800	—	−1,500	−53,900
Net acres out of production	5,900	11,000	17,300	6,300	18,100	38,900	10,700	34,600	113,400
AUM grazing @ 3 ac/AUM*	2,000	3,700	5,800	2,100	6,000	13,000	3,600	11,500	37,800
Total animal units—annual*	200	300	500	200	500	1,100	300	1,000	3,200
Grazing value @ $6.00/AUM*	11,800	22,100	34,500	12,600	36,200	77,800	21,500	69,200	226,800

*Total may not be exact due to rounding.

occurs, residents become less oriented toward other individuals in the community and more oriented toward institutions and extra-community forces. It includes a general decline in local autonomy, exposure to different norms, and a fragmenting of the existing social order and the building of a new one.

The non-Indian culture and way of life is centered around two features—the community, which is generally small, and the agrarian nature of the society. The persons who live in the area are accustomed to a generally slow pace of living, relatively little congestion, a well-integrated, stable society with an established sense of community where individuals are known and most face-to-face contact is with familiar persons. There are differences; nevertheless, there is still an appearance of similarity of interests and values. Agriculture has long been the principal economic force in the area and the region's culture is firmly rooted in the American agricultural ideology.[11]

Initially, the impacts of urbanization will be greatest on the persons and communities closest to the actual development sites, with the impacts then diminishing in a descending scale with distance from the development site. In the long run, however, all persons in the area will be affected to some extent. The smaller the scale of development, the more likely it is that the impacts will be localized.

Within the development areas, there are differences of opinion concerning coal development. One rancher may sell or lease his ranch and his neighbor will feel betrayed. Some residents feel that their lifestyles will be destroyed, whereas others feel that development will be beneficial. Differences of opinion have touched nearly every person in the development areas, and have spread throughout the United States. Confusion reigns supreme, and within the development areas rumors spread like prairie fires. There is, however, one common denominator shared by most residents of the NGP: They know coal development will affect their lives—but they are not certain as to the degree and nature of impact.

The Indian and non-Indian have more or less adjusted to the lifestyles of each other over the past decades. There have been conflicts; however, the adjustments that have been made are based on a largely rural society. As the area becomes more urbanized with an influx of workers and their families, the mutual understanding and accommodations made during the past by the resident non-Indian and Indians may be severely tested, and even break down, unless further adjustments are made by all parties concerned. The lifestyle of the present residents, both Indians and non-Indians, will be changed. Whether or not this will result in environmental and cultural decline will depend upon the demands placed upon that system. If a large influx of "outsiders" were to move onto the reservations, both the resident Indians and resident non-Indians would become minorities within their own environs. The present lifestyle, the cultural values, and the language of the Indians will undoubtedly be diluted to some extent with this new admixture. Out of this could come a diverse cultural experience but also the loss of some of the existing Indian cultural values.

Social change would be expected with or without coal development. If coal development were to occur at CDP I levels, adjustments could be made without socio-psychological trauma. However, at CDP II and CDP III levels, the time required to prevent a socio-psychological trauma will be absent. In attempting to understand the socio-economic impacts on the reservations, it is important to remember that they have been development islands in the past but that they must be considered part of the entire community in the NGP. In some cases, very intensive and extensive coal development will be taking place on and adjacent to the reservations. These developments will be intra-regional and inter-sectorial; coal development will increase competition on and off the reservation for capital, manpower, housing, public services, and other facilities. This will contribute greatly to internal and external socio-economic pressures on the Indian, non-Indian, and "newcomers."

Probably one of the major impacts will be the sheer size of the population growth within a very short time. Large numbers of persons with different values and orientations will move into the area because of the developmental activities. Most will likely move into rather small communities, doubling, tripling, or even quadrupling the present population. Congestion, crowding, the physical and mental stress associated with these phenomena are all likely to be severe in many parts of the region, and most severe during the short-term construction period of development. All of these impacts are likely to reduce the perceived quality of life for many of the people already living there.

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[11] See, for example, Higbee, Edward, *Farms and Farmers in an Urban Age* (New York: Twentieth Century Fund, 1963) and Salisbury, Robert H., "Agriculture and Natural Resources," in Peltason, J. W. and Burns, James M., *Functions and Policies of American Government* (Englewood Cliffs, N.J.: Prentice-Hall, 1967).

With these changes, many residents, landowners as well as others, will be challenged to modify their current lifestyles in order to accommodate changes in their environment. Some persons on fixed incomes (i.e., retirees) may be dislocated because of an increase in the cost of housing. Sportsmen may find their favorite recreational areas disrupted by mining activities or "overcrowded" by newcomers.

The changes in the culture and way of life of the area that may follow the development will vary not only with the level of development which occurs, but with the pace of that development. One likely set of impacts which would follow rapid development might be termed the "boom town" syndrome.[16] Gilmore and Duff describe the syndrome as a "whole family of mental health symptoms and problems" that results from the rapid influx of a great many people. Families are crowded together in mobile homes in a strange environment; newly arriving families, particularly the blue collar families, seek acceptance into the community; social cohesion suffers as alienation and emotional distress feed on each other; and crime rates, suicide attempt rates, and alcoholism tend to increase. In short, the quality of life of persons, both newcomers and residents of the area, is degraded.

Of course, the boom might turn into a "bust" if outside factors force the closing of mining activities in the area. This, then, would lead to another series of impacts for the communities involved.

The family as a social unit is likely to be greatly affected by the changes introduced by the energy development activities. Traditionally, the rural family has been a strong social unit. In the rural setting, cohesiveness of the family is both the result of and mandatory for economic survival.[17] With the advent of urbanization and industrialization in the NGP, the family is likely to cease to be a basic unit of production. Individuals may seek employment outside of traditional family enterprises, such as the family farm, ranch, or store. Extended families within one household are less likely to exist as people migrate to other employment. These new values and interests often change existing values and culture. Such change generates stress on the residents, leading to a feeling of isolation, and sometimes alienation and conflict between established groups and newcomers. In other words, conflicts between some ranchers and miners could develop. Some communities might be "taken over" by newcomers, and long-term residents may withdraw physically or in terms of participation in community activities.

As the newly emerging community stabilizes, it may present new job opportunities and a higher economic standard of living than was possible in the old community. The variety of cultural and recreational opportunities would probably increase as would the availability of services.

High emigration rates have existed throughout virtually the entire region for the past several decades for almost all age groups.[18] One possible impact of development is that the emigration rates could be significantly reduced in large part because of the increased availability of employment opportunities within the area. If this occurs, then an additional measure of stability in terms of the residents could be anticipated.

Most of the rural communities of the area have well-defined and long-established networks of social and political relationships. It is likely that one of the results of the anticipated changes in the area will be the fragmentation of these groups by the intrusion of relatively large numbers of persons into the area, and, in effect, the creation of a new social order. Another likely impact will be the dilution of political power of the historically dominant groups (primarily landowners) within the impacted area. In the long run, new political alliances and groups will likely develop.

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[16] Gilmore, John S. and Duff, Mary K., "Statement to Public Lands Subcommittee, U.S. Senate, January 19, 1976" (Denver: mimeo, 1976) p. 19.

[17] Larson, Don, "Report to Work Group," (Brandon, SD: mimeo, 1976) p. 11.

[18] Professor Audie Blevins, personal communication, April 1976.

A further major change in the way of life for some of the people in the area has been an increased social activity in planning and organizing for anticipated change. In effect, the anticipated environmental changes have resulted in activating groups and leaders into overt action. Many people who previously had not participated in community, civic, or political affairs have devoted large amounts of time and energy to organizing and participating in community affairs related to forthcoming development.

Some of the impacts have already begun to occur. There has been some population growth. One notable change among a sizable group of the population has been the creation of an aura of uncertainty and "unsettledness" about their future. Questions such as the following occur: "How much development will take place?", "When will the development take place?", "How fast?", "What will happen to the water table?", "Can the land be reclaimed effectively?" No longer can many people view the future in the same manner as they have for many years. Uncertainty about the future has materially reduced the quality of the present for many persons.

In sum, the culture and way of life of persons in the impacted areas of the NGP will likely shift from the agrarian-focused way of life which now exists to a larger, more urbanized way of life with all the advantages and disadvantages which that will entail. Some of the changes would likely come about without the energy development activities, but at a very much slower pace—over decades instead of in a few years—while others may not have occurred at all.

Post-Coal Development

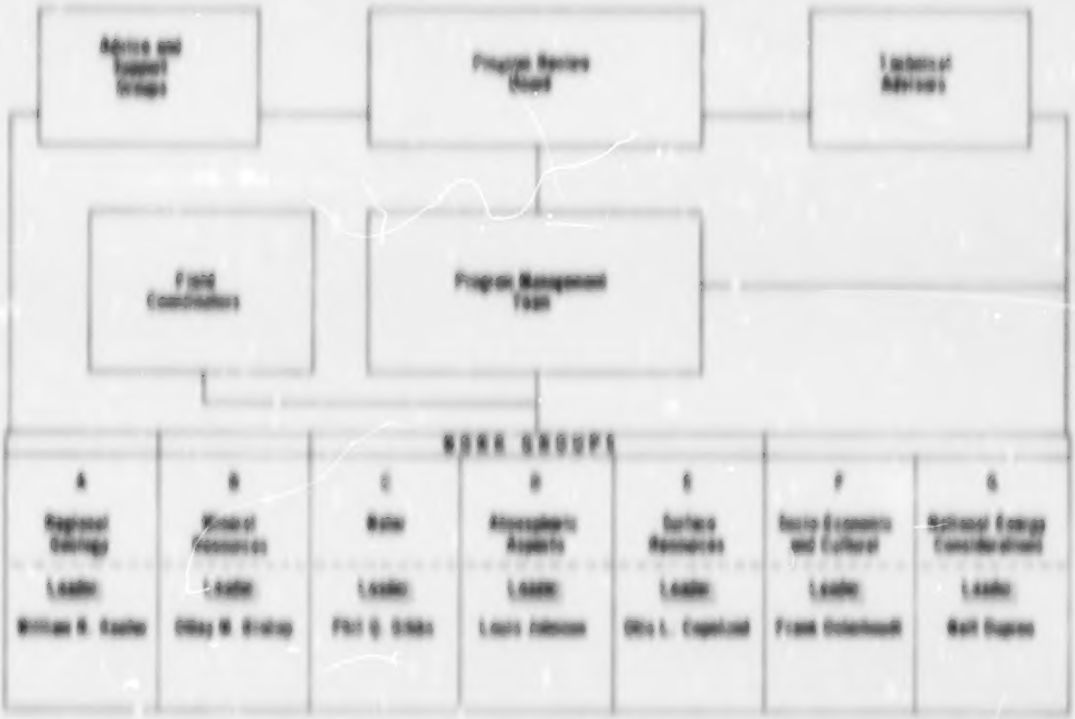
This section has attempted to illustrate what may happen as a result of different levels of coal development in the NGP. The impacts discussed deal primarily with what may be anticipated through the year 2000. However, effects of such development will continue after 2000. Coal development and coal utilization may be a long-term factor in satisfying the Nation's energy demands. If this is the case, the effects of coal development can be expected to be amplified in the future.

Conversely new technology may reduce the importance of coal. Solar energy and fast breeder reactors and other new technology may end coal's dominance in the NGP. When this occurs, what adjustments will be required of the residents of the NGP? Will they again be required to make large adjustments to accommodate changing economic, social, and cultural conditions?

Little thought has been given to the post-coal development era in the NGP, but it should be kept in mind and taken into consideration in future policies and decisions concerning the NGP.

APPENDIX A

ORGANIZATION FOR NORTHERN GREAT PLAINS RESOURCES PROGRAM


Advice and Support Groups
Program Review Board
Technical Advisors
Field Coordinators
Program Management Team
WORK GROUPS
A
Regional Geology
Leader
William R. Keefer
B
Mineral Resources
Leader
[illegible] M. Bishop
C
Water
Leader
Phil Q. Gibbs
D
Atmospheric Aspects
Leader
Louis Johnson
E
Surface Resources
Leader
Otis L. Copeland
F
Socio-Economic and Cultural
Leader
Frank Osterhoudt
G
National Energy Considerations
Leader
Walt Dupree

APPENDIX B

REPOSITORIES

North Dakota

Bureau of Land Management
North Dakota Project Office
P.O. Box 1072
Dickinson, ND 58601

North Dakota State Capitol
Bismarck, ND 58501

Department of Business and Industrial Development
State Office Building
900 East Boulevard
Bismarck, ND 58501

Game and Fish Department
2121 Lovett Avenue
Bismarck, ND 58501

Geological Survey
Third Floor, Leonard Hall
University Station
Grand Forks, ND 58201

Soil Conservation Committee
18th Floor–State Capitol
Bismarck, ND 58501

Water Commission
State Office Building
900 East Boulevard
Bismarck, ND 58501

Valley City State College
Valley City, ND 58072

North Dakota State School of Science
Wahpeton, ND 58075

North Dakota State University Library
Attn: Mrs. Eloise Jackson
Fargo, ND 58102

State Planning Director
State Capitol
Bismarck, ND 58501

Health Department
14th Floor–State Capitol
Bismarck, ND 58501

Indian Affairs Commission
18th Floor–State Capitol
Bismarck, ND 58501

Land Department
Sixth Floor–State Capitol
Bismarck, ND 58501

Library Commission
Highway 83 North
Bismarck, ND 58501

Public Service Commission
12th Floor–State Capitol
Bismarck, ND 58501

Dickinson State College
Dickinson, ND 58601

Jamestown College Library
Jamestown, ND 58401

University of North Dakota
Minot, ND 58701

UND–Williston Center
Williston, ND 58801

Minot State College Library
Minot, ND 58701

North Dakota State University
School of Forestry
Bottineau, ND 58318

Mayville State College
Mayville, ND 58257

Ecological Studies
University of North Dakota
Grand Forks, ND 58201

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South Dakota

Sixth Planning & Development District
P.O. Box 1586
Rapid City, SD 57701

South Dakota School of Mines and
Technology
Rapid City, SD 57701

Old West Regional Commission
Rapid City, SD 57701

Dakota State College
Madison, SD 57042

South Dakota State Capitol
Pierre, SD 57501

U.S. Bureau of Mines
Liaison Officer
Attn: James Aase
Federal Bldg.–Court House
515 Ninth Street
Rapid City, SD 57701

University of South Dakota
Vermillion, SD 57069

South Dakota State University
Brookings, SD 57006

State Planning Bureau
State Capitol
Pierre, SD 57501

Black Hills State College
Spearfish, SD 57783

State Library Commission
Pierre, SD 57501

Northern State College
Aberdeen, SD 57401

Dr. Harold E. Wittig, Director
Augustana Research Institute
204 Gilbert Science Center
Sioux Falls, SD 57102

Vern Butler, Secretary
Dept. of Natural Resources
Development
Office Bldg. 2
State Capitol
Pierre, SD 57501

Donald E. Loudner
Coordinator, Indian Affairs
State Capitol
Pierre, SD 57501

Dr. Duncan McGregor, Director
S. Dak. Geological Survey
Vermillion, SD 57069

Mr. Allen Lockner, Secretary
Dept. of Environmental Protection
Office Bldg. 2
State Capitol
Pierre, SD 57501

John Popowski, Secretary
Dept. of Game, Fish, & Parks
Office Bldg. 1
State Capitol
Pierre, SD 57501

Montana

Old West Regional Commission
Fratt Building, Suite 306A
Billings, MT 59101

Bureau of Land Management
Montana State Office
316 North 26th Street
Billings, MT 59101

Bureau of Land Management
Miles City District
P.O. Box 940
Miles City, MT 59301

University of Montana
Missoula, MT 59801

Montana School of Mineral Science and
Technology
Butte, MT 59701

Montana (Cont.)

Department of Fish and Game
State Capitol
Helena, MT 59601

Department of Natural Resources and
Conservation
State Capitol
Helena, MT 59601

Montana Energy Advisory Council
c/o Lt. Governor's Office
Capitol Building
Helena, MT 59601

Montana State Capitol
Helena, MT 59601

Eastern Montana College
Billings, MT 59101

Custer Community College
Miles City, MT 59301

Dawson Community College
Glendive, MT 59330

Documents Librarian
Montana State University Library
Bozeman, MT 59715

College of Great Falls
Great Falls, MT 59401

Carroll College
Helena, MT 59601

Montana State Library
Documents Section
930 East Lyndale Avenue
Helena, MT 59601

Department of State Lands
Capitol Building
Helena, MT 59601

Department of Intergovernmental Relations
Research & Information Systems Library
Capitol Post Office
Helena, MT 59601

State Environmental Library
Room 208A
Natural Science Building
University of Montana
Missoula, MT 59801

Bureau of Indian Affairs
Billings Area Office
316 North 26th Street
Billings, MT 59101

Crow Indian Agency
Mr. George LaVerdure, Superintendent
Crow Agency, MT 59022

Fort Peck Indian Agency
Burton Rider, Superintendent
Poplar, MT 59255

Northern Cheyenne Indian Agency
Mr. Alonzo Spang, Sr., Superintendent
Lame Deer, MT 59043

Nebraska

Gift & Exchange Section
Serials Dept.
University of Nebraska Library
Lincoln, NE 68508

Eppley Library
University of Nebraska
Omaha, NE 68132

State Office of Planning and Programming
P.O. Box 94601
State Capitol
Lincoln, NE 68509

Missouri River Basin Commission Library
10050 Regency Circle
Omaha, NE 63114

Kearney State College
Kearney, NE 68847

Chadron State College
Chadron, NE 69337

Wayne State College
Wayne, NE 68787

Nebraska (Cont.)

Nebraska State Capitol
Lincoln, NE 68509

Wyoming

Sheridan College Library
Sheridan, WY 82801

Wyoming State Capitol
Cheyenne, WY 82001

Albany County Library
405 Grand Avenue
Laramie, WY 82070

Big Horn County Library
Box 231
Basin, WY 82410

Campbell County Library
412 Gillette Avenue
Gillette, WY 82716

Carbon County Library
Court House
Rawlins, WY 82301

Converse County Library
300 Walnut Street
Douglas, WY 82633

Crook County Library
Sundance, WY 82729

Fremont County Library
451 North Second Street
Lander, WY 82520

Goshen County Library
2001 East A
Torrington, WY 82240

Hot Springs County Library
344 Arapahoe
Thermopolis, WY 82443

Weston County Library
113 West Main
Newcastle, WY 82701

University of Wyoming
Coe Library
Laramie, WY 82070

Laramie County Library
2800 Central
Cheyenne, WY 82001

Lincoln County Library
Kemmerer Court House
Kemmerer, WY 83101

Natrona County Library
307 East Second
Casper, WY 82601

Niobrara County Library
467 South Main
Lusk, WY 82225

Park County Library
Cody, WY 82414

Platte County Library
904 Ninth Street
Wheatland, WY 82201

Sheridan County Library
45 West Loucks
Sheridan, WY 82801

Sublette County Library
Box 628
Pinedale, WY 82941

Sweetwater County Library
177 North Center
Box 552
Green River, WY 82935

Teton County Library
Box 1629
Jackson, WY 83025

Uinta County Library
Box AA
Evanston, WY 82930

Washakie County Library
1019 Coburn Avenue
Worland, WY 82401

Wyoming (Cont.)

Northwest Community College Library
Powell, WY 82435

Central Wyoming College Library
Riverton, WY 82501

Western Wyoming College Library
Rock Springs, WY 82901

Sheridan College
Mary Brown Kool Library
Sheridan, WY 82801

Eastern Wyoming Community College Library
Torrington, WY 82240

Bureau of Land Management
P.O. Box 1828
Cheyenne, WY 82001

Wyoming Geological Survey
P.O. Box 3008
University Station
Laramie, WY 82071

Wyoming State Library
Supreme Court Building
Cheyenne, WY 82002

Wind River Indian Agency
Mr. Clyde Hobbs, Superintendent
Fort Washakie, WY 82514

Colorado

National Park Service
6555 Parfet Street
P.O. Box 25287
Denver, CO 80225

Northern Great Plains Resources Program
Denver Federal Center
Building 67, Room 820B
P.O. Box 25007
Denver, CO 80225

Environmental Protection Agency
Library
1860 Lincoln
Denver, CO 80203

USGS Library
Building 25
Denver Federal Center
Denver, CO 80225

Fish and Wildlife Service Library
10597 West Sixth Avenue
P.O. Box 25486
Denver, CO 80225

Bureau of Mines Library
Building 20
Denver Federal Center
Denver, CO 80225

Bureau of Reclamation Library
Denver Federal Center
Building 67
Denver, CO 80225

Bureau of Land Management
Library
Denver Federal Center
Building 50
Denver, CO 80225

Colorado Technical Reference Center
University of Colorado
Norlin Library—Room 208
Boulder, CO 80302

Documents Department
Colorado State University Libraries
Ft. Collins, CO 80523

Bureau of Outdoor Recreation
Denver Federal Center
P.O. Box 25387
Denver, CO 80225

Forest Service Library
Denver Federal Center
Building 85
Denver, CO 80225

State Geological Survey Library
1845 Sherman
Denver, CO 80203

Colorado (Cont.)

Conservation Library
Attn: Kay Collins
1357 Broadway
Denver, CO 80203

Grand Junction Public Library
Grand Junction, CO 81501

Garfield County
Department of Health and Environmental
Protection
Library
2014 Lake Avenue
Glenwood Springs, CO 81601

Moffat County Planning Department Library
Moffat County
Craig, CO 81625

Colorado School of Mines
Attn: Geraldine Bariani
Arthur Lakes Library
Golden, CO 80401

Pikes Peak Regional Library
Mr. Ken Dowlin, Director
Penrose Public Library
Box 1579
Colorado Springs, CO 80901

California

Electric Power Research Institute
4312 Hillview Avenue
Palo Alto, CA 94304

Water Resources Center Archives
Mrs. Beth Willard, Librarian
2081 Engineering I
University of California
Los Angeles, CA 90024

U.S. Geological Survey
Br. Western Environmental Geol.
Attn: Richard R. Doell
345 Middlefield Road
Menlo Park, CA 94025

Los Angeles Public Library
630 West Fifth
Los Angeles, CA 90017

Documents Department
General Library
University of California
Berkeley, CA 94720

Missouri

State Library
High Street
Jefferson City, MO 65101

Virginia

U.S. Geological Survey Library
Attn: Mr. Glenn H. Borders
National Center--MAIL STOP 950
12201 Sunrise Valley Drive
Reston, VA 22092

Washington, D.C.

National Coal Association Library
Coal Building
1130--17th Street, NW.
Washington, DC 20036

Department of Interior Library
18th and "C" Streets, NW.
Washington, DC 20240

Environmental Protection Agency Library
Washington, DC 20460

Department of Agriculture
Library
Washington, DC 20250

Federal Energy Administration Library
Washington, DC 20461

Dr. Allen F. Agnew
Environmental Policy Division
Congressional Research Service
Library of Congress (Stop 303)
Washington, DC 20540

Washington, D.C. (Cont.)

Council on Environmental Quality
Attn: Steven Jellinek
Exec. Office of the President
722 Jackson Place, NW.
Washington, DC 20006

Energy Research & Development Administration
c/o Robert Rabin
Washington, DC 20545

Idaho

Social Science Library
Documents
University of Idaho Library
Moscow, ID 83843

Utah

Documents Librarian
Weber State College Library
Ogden, UT 84403

Texas

Houston Public Library
Houston, TX 77002

New York

The New York Public Library
The Research Libraries
Acquisition Division
Fifth Avenue & 42nd Street
New York, NY 10018

Michigan

Detroit Public Library
5201 Woodward
Detroit, MI 48202

Lansing Public Library
401 South Capitol Avenue
Lansing, MI 48933

Illinois

Public Lands Project
Northwestern University Library
2040 Sheridan Road
Evanston, IL 60201

New Mexico

University of New Mexico
Zimmerman Library
Government Publications Section
Albuquerque, NM 87110

APPENDIX C

PRINCIPAL AGENCY PARTICIPANTS IN NORTHERN GREAT PLAINS RESOURCES PROGRAM

Program Review Board

Royston Hughes, Chairman, Assistant Secretary, Department of Interior
Alvin L. Alm, Assistant Administrator, Environmental Protection Agency
Robert W. Long, Assistant Secretary, Department of Agriculture
Stanley K. Hathaway, former Governor of Wyoming
Richard F. Kneip, Governor of South Dakota
James Exon, Governor of Nebraska
Thomas L. Judge, Governor of Montana
Arthur A. Link, Governor of North Dakota
Ed Herschler, Governor of Wyoming
W. W. Lyons, Executive Secretary, Deputy Under Secretary, Department of Interior

Technical Advisors

Frank E. Clarke, Department of Interior
Dr. William Moffat, Department of Interior
John W. Neuberger, Missouri River Basin Commission
Warren Wood, Old West Regional Commission

Program Management Team Members and Principal Participants

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Robert Potter, Department of Agriculture
Daniel Ricker, Department of Agriculture
Robert Jones, Bureau of Land Management
William Christiansen, State of Montana
John Goers, State of Montana
Ted Clack, State of Montana
Jack Neckels, State of North Dakota
Dan Bucks, State of South Dakota
Oscar Lund, State of South Dakota
J. D. Brunk, State of Wyoming
Mike York, State of Wyoming
Donald Nelson, State of Nebraska
Warren White, State of Nebraska

Field Representatives

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APPENDIX C—Continued

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APPENDIX D

SUPPORTING DOCUMENTS

Declaration of Indian Rights to the Natural Resources in the Northern Great Plains States

Rehabilitation Potentials and Limitations of Surface-Mined Land in the Northern Great Plains

Possible Development of Water From Madison Group and Associated Rock in Powder River Basin, Montana–Wyoming

APPENDIX E

MAPS

Plate 3—Suitability of Dominant Soils for Rehabilitation
Plate 5—Proposed Wilderness and Wild Land
*Plate 7—Major Eco-Systems and Surface Rehabilitation Factors
*Plate 8—Rehabilitation Response Units
Plate 10—Surface Ownership
Plate 11—Minerals Management—Montana, East Half
Plate 12—Minerals Management—North Dakota
Plate 13—Minerals Management—South Dakota
**Plate 14—Minerals Management—Wyoming
Plate B-3—Surface Minable Coal Deposits
Plate B-4—Base Development Forecast
Plate B-5—Most Probable Development Forecast
Plate B-6—Extensive Development Forecast
Plate B-7a—Coal Mineral Right Ownership—Bull Mountain and Powder River Regions
Plate B-7b—Coal Mineral Right Ownership—Fort Union Region

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*Plates 7 and 8 are referred to as Figures 1 and 2, respectively, in the Supporting Document prepared by Paul Packer.
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